TRANSGLOBE ENERGY CORPORATION

ANNUAL INFORMATION FORM

Year Ended December 31, 2018

Dated March 13, 2019

TABLE OF CONTENTS

	Page
ABBREVIATIONS	3
CONVERSIONS	3
CURRENCY AND EXCHANGE RATES	4
FORWARD-LOOKING STATEMENTS	4
NON-GAAP MEASURES	6
CERTAIN DEFINITIONS	6
TRANSGLOBE ENERGY CORPORATION	8
GENERAL DEVELOPMENT OF THE BUSINESS	9
DESCRIPTION OF THE BUSINESS AND PRINCIPAL PROPERTIES	10
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	15
DIVIDEND POLICY	31
DESCRIPTION OF CAPITAL STRUCTURE	32
MARKET FOR SECURITIES	32
PRIOR SALES	33
ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER	33
DIRECTORS AND OFFICERS	33
INTERESTS OF EXPERTS	35
LEGAL PROCEEDINGS AND REGULATORY ACTIONS	36
INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	36
TRANSFER AGENT AND REGISTRAR	36
MATERIAL CONTRACTS	36
AUDIT COMMITTEE INFORMATION	36
CANADIAN INDUSTRY CONDITIONS	37
RISK FACTORS	45
ADDITIONAL INFORMATION	56

SCHEDULE "A"	Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor
SCHEDULE "B"	Report of Management and Directors on Oil and Gas Disclosure
SCHEDULE "C"	Charter of Audit Committee

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
bbls/d	barrels per day
bopd	barrels of oil per day
Mbopd	thousand barrels of oil per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet

Other

boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
MMboe	million barrels of oil equivalent
km^2	square kilometres
m^3	cubic metres
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

We have adopted the standard of 6 mcf: 1 bbl when converting natural gas to oil and 1 bbl: 6 mcf when converting oil to natural gas. **Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value**.

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	0.28174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls oil	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMBtu	0.950

CURRENCY AND EXCHANGE RATES

All dollar amounts in this AIF, unless otherwise indicated, are stated in United States ("**U.S.**") currency. TransGlobe Energy Corporation ("**TransGlobe**" or the "**Company**") uses the U.S. dollar as reporting currency for its consolidated financial statements. The exchange rates for the average of the daily closing rates during the period and the end of period closing rate for the U.S. dollar in terms of Canadian dollars as reported by the Bank of Canada were as follows for each of the years ended December 31, 2018, 2017 and 2016.

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
End of Period	C$1.36	C$1.26	C$1.34
Period Average	C$1.29	C$1.30	C$1.32

FORWARD-LOOKING STATEMENTS

This AIF may include certain statements deemed to be "forward-looking statements" or "future oriented financial information" within the meaning of applicable Canadian and United States securities laws. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "may", "will", "should", "expect", "plan", "anticipate", "continue", "believe", "estimate", "predict", "project", "potential", "targeting", "intend", "could", "might", "continue", "should" or the negative of these terms or other comparable terminology. These statements are only predictions. In addition, this AIF may contain forward-looking statements attributed to third-party industry sources. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon.

Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur and may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Forward-looking statements in this AIF include, but are not limited to, statements with respect to:

- the performance characteristics of the Company's oil and natural gas properties;
- oil and gas production levels;
- the quantity of oil and gas reserves;
- capital expenditure programs;
- supply and demand for oil and gas, and commodity prices;
- drilling plans;
- expectations regarding the Company's ability to raise capital and to continually add to reserves though acquisitions, exploration and development;
- the budget for the exploration program;
- future development costs;
- future reserves growth and the success of the 2019/2020 exploration program;
- the continuation of the Company's marketing of its own Egypt entitlement oil on a go-forward basis and the resulting reduced credit risk;
- the satisfaction of work commitments in Egypt;
- the timing and execution of having a drill-ready prospect inventory prepared for South Ghazalat;
- estimated timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- anticipated average production for 2019;
- expected exploration and development spending and the funding thereof;
- treatment under governmental regulatory regimes and tax laws;
- realization of the anticipated benefits of acquisitions and dispositions;
- tax horizon;
- adverse technical factors associated with exploration, development, production, transportation or marketing of crude oil reserves; and
- changes or disruptions in the political or fiscal regimes in the Company's areas of activity.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that some or all of the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this AIF and certain documents incorporated by reference herein are expressly qualified by this cautionary statement.

Forward-looking information and statements contained in this document include the payment of dividends, including the timing and amount thereof, and the Company's intention to declare and pay dividends in the future under its current dividend policy. Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its strategy, ongoing production maintenance, growth through acquisitions, fluctuations in working capital and the timing and amount of capital expenditures and anticipated business development capital, payment irregularity in Egypt, debt service requirements and other factors beyond the Company's control. Further, the ability of the Company to pay dividends will be subject to applicable laws (including the satisfaction of the liquidity and solvency tests contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness.

Although the forward-looking statements contained in this AIF are based upon assumptions which management of the Company believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this AIF, the Company has made assumptions regarding: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and gas; the impact of increasing competition; conditions in

general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; future operating costs; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and other matters.

Actual operational and financial results may differ materially from TransGlobe's expectations contained in the forward-looking statements as a result of various risk factors, many of which are beyond the control of the Company. These risk factors include, but are not limited to:

- unforeseen changes in the rate of production from the Company's oil and gas fields;
- changes or disruptions in the political or fiscal regimes in the Company's areas of activity;
- continued volatility in market prices for crude oil and natural gas;
- actions taken by OPEC with respect to the supply of oil;
- exposure to third party credit risk due to the receivable due from EGPC;
- general economic conditions in Canada, the United States, Egypt and globally;
- general economic stability of the Company’s financial lenders and creditors;
- payment of crude oil and natural gas marketing contracts and both associated and non-associated financial hedging instruments;
- adverse technical factors associated with exploration, development, production, transportation or marketing of the Company's crude oil and natural gas reserves;
- changes in Egyptian or Canadian tax, energy or other laws or regulations;
- geopolitical risks associated with the Company's operations in Egypt;
- capital expenditure programs, including changes in capital expenditures;
- delays in production starting up due to an industry shortage of skilled manpower, equipment or materials;
- the cost of inflation;
- the performance characteristics of the Company's oil and gas properties and the Company's success at acquisition, exploitation and development of reserves;
- failure to achieve production targets on timelines anticipated or at all;
- changes or fluctuations in production levels;
- the quantity of oil and gas reserves;
- supply and demand for oil and gas, and commodity prices;
- the Company's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- changes to treatment under governmental regulatory regimes and tax laws;
- failure to realize the anticipated benefits of acquisitions and dispositions;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- risks inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land and skilled personnel;
- incorrect assessments of the value of acquisitions;
- competition from other producers;
- lack of availability of qualified personnel;
- credit risks;
- the potential for reserves evaluators' estimates and assumptions to be inaccurate;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "*Risk Factors*" in this AIF.

Forward-looking statements and other information contained herein concerning the oil and natural gas industry in the countries in which TransGlobe operates and the Company's general expectations concerning this industry are based on estimates prepared by management of the Company using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

The Company has included the above summary of assumptions and risks related to forward-looking information provided in this AIF in order to provide Shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company believes that the expectations reflected in the forward-looking statements contained in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct, and investors should not attribute undue certainty to, or place undue reliance on, such forward-looking statements. Such statements speak only as of the date of this AIF. If circumstances or management’s beliefs, expectations or opinions should change, the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable Canadian and United States securities laws. Please consult the Company's SEDAR profile at www.sedar.com and the Company's profile on the Electronic Data Gathering and Retrieval System of the U.S. Securities and Exchange Commission ("EDGAR") at www.sec.gov for further, more detailed information concerning these matters.

NON-GAAP MEASURES

Netback

Netback is a measure of operating results and is computed as sales net of royalties (all government interests, net of income taxes), operating expenses, current taxes and selling costs. The Company's netbacks include sales and associated costs of production from inventoried crude oil sold during the period. Royalties and taxes associated with inventoried crude are recognized at production. Netbacks fluctuate depending on the timing of entitlement oil sales. Management believes that netback is a useful supplemental measure to analyze operating performance and provide an indication of the results generated by the Company's principal business activities prior to the consideration of other income and expenses. Netback does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

CERTAIN DEFINITIONS

In this AIF, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means the Business Corporations Act, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**AER**" means the Alberta Energy Regulator;

"**AIF**" means this Annual Information Form and the appendices attached hereto;

"**AIM**" means the Alternative Investment Market of the London Stock Exchange;

"**ATB**" means Alberta Treasury Branch;

"**Board**" means the Board of Directors of the Company;

"**Borrowing Base Facility**" means the $39.3 million borrowing facility which was terminated in December 2016;

"**Brent**" means the reference price paid in U.S. dollars for a barrel of light sweet crude oil produced from the Brent field in the UK sector of the North Sea;

"**Business Day**" means a day, other than a Saturday or Sunday, or a statutory holiday, on which major Canadian chartered banks are open for business in Calgary, Alberta;

"**C$**" means Canadian dollars;

"**CHR&G**" means the Compensation Human Resources & Governance Committee;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by The Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**Common Shares**" means the common shares of the Company;

"**Debentures**" means the C$97,750,000 aggregate principal amount of 6.00% convertible unsecured subordinated debentures which matured on March 31, 2017;

"**Dry Hole**" or "**Dry Well**" or "**Non-Productive Well**" means a well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well;

"**DSU Plan**" means the deferred share unit plan of the Company;

"**EDGAR**" means the Electronic Data Gathering and Retrieval System of the U.S. Securities and Exchange Commission;

"**EGPC**" means the Egyptian General Petroleum Corporation;

"**Egypt**" means the Arab Republic of Egypt;

"**Exploratory Well**" means a well drilled either in search of a new, as-yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir;

"**GLJ**" means GLJ Petroleum Consultants Ltd, independent petroleum consultants;

"**GLJ Report**" means the report of GLJ dated January 22, 2019 evaluating the crude oil, natural gas and NGL reserves of the Company as at December 31, 2018;

"**Gross**" or "**gross**" means:

(i) in relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(ii) in relation to wells, the total number of wells in which the Company has an interest; and

(iii) in relation to properties, the total area of properties in which the Company has an interest;

"**IFRS**" means International Financial Reporting Standards as issued by the International Accounting Standards Board;

"**Mercuria**" means Mercuria Energy Trading SA;

"**Nasdaq**" means the Nasdaq Global Select Market;

"**Net**" or "**net**" means:

(i) in relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;

(ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(iii) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

"**NGLs**" means natural gas liquids;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**NI 51-102**" means National Instrument 51-102 - *Continuous Disclosure Obligations*;

"**NW Gharib**" means the North West Gharib Concession area in Egypt;

"**NW Sitra**" means the North West Sitra Concession area in Egypt;

"**OECD**" means the Organization for Economic Co-operation and Development;

"**OPEC**" means the Organization of Petroleum Exporting Countries;

"**PSC**" means production sharing concession;

"**PSU Plan**" means the performance share unit plan of the Company;

"**RBL**" means revolving reserves-based lending facility;

"**RHSE&S Committee**" means the Reserves, Health, Safety, Environment & Social Responsibility Committee;

"**RSU Plan**" means the restricted share unit plan of the Company;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators;

"**S Ghazalat**" means the South Ghazalat Concession area in Egypt;

"**SE Gharib**" means the South East Gharib Concession area in Egypt;

"**Shareholders**" means the holders of Common Shares of the Company;

"**SMBC**" means Sumitomo Mitsui Banking Corporation;

"**South Alamein**" means the South Alamein Concession area in Egypt;

"**SW Gharib**" means the South West Gharib Concession area in Egypt;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, each as amended from time to time;

"**TPI**" means TransGlobe Petroleum International Inc.;

"**TransGlobe**" or the "**Company**" means TransGlobe Energy Corporation, a corporation organized and registered under the laws of Alberta, Canada, and as the context requires, its subsidiary companies;

"**TSX**" means the Toronto Stock Exchange;

"**U.S.**" means the United States of America;

"**West Bakr**" means the West Bakr Concession area in Egypt;

"**West Gharib**" means the West Gharib Concession area in Egypt; and

"**Yemen**" means the Republic of Yemen.

Certain other terms used herein but not defined herein are defined in NI 51-101, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

TRANSGLOBE ENERGY CORPORATION

General

TransGlobe was incorporated on August 6, 1968 and was organized under variations of the name "Dusty Mac" as a mineral exploration and extraction venture under *The Company Act* (British Columbia). In 1992, the Company entered the oil and gas exploration and development industry in the United States and later in Yemen, Canada and Egypt, ceasing operations as a mining company. The Company changed its name to TransGlobe Energy Corporation on April 2, 1996 and on June 9, 2004, the Company continued from the Province of British Columbia to the Province of Alberta pursuant to the ABCA. The Company's U.S. oil and gas properties were sold in 2000 to fund opportunities in Yemen and the Company's previous Canadian oil and gas assets and operations were divested in early 2008 to assist with the funding of opportunities in Egypt and Yemen. In 2015, the Company relinquished and divested all of its interests in Yemen. In 2016, the Company re-entered Canada with the acquisition of production and working interests in certain facilities in west central Alberta.

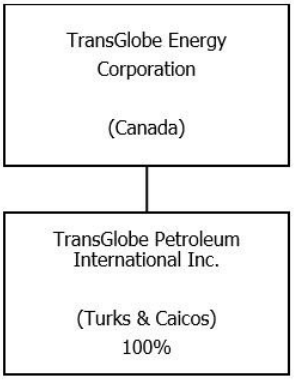
TransGlobe and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of oil and natural gas properties in Egypt and Alberta, Canada. The Company currently employs 67 full-time employees and 16 full-time consultants.

The Common Shares have been listed on the TSX under the symbol "TGL" since November 7, 1997 and on the Nasdaq under the symbol "TGA" since January 18, 2008. Prior to listing on the Nasdaq, the Company had its U.S. listing on the American Stock Exchange since 2003. On June 29, 2018 the Common Shares were listed on the AIM under the symbol "TGL".

The Company's principal office is located at 2300, 250 - 5th Street S.W., Calgary, Alberta, T2P 0R4. The Company's registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1. The Company's executive office is located at 105 Victoria Street, London, UK, SWIE 6QT.

Intercorporate Relationships

The following organization chart and table present the name and jurisdiction of incorporation of the Company's material subsidiaries as at the date of this document. The chart and table do not include all of the subsidiaries of TransGlobe. The assets and revenues of excluded subsidiaries did not, individually exceed 10%, and in aggregate exceed 20% of the total consolidated assets or total consolidated revenues of TransGlobe as at the date of this document.



TransGlobe's Canadian properties are owned by TransGlobe Energy Corporation. The following table sets out the name and jurisdiction of incorporation of the subsidiaries beneficially owned, controlled or directed, directly or indirectly, by TPI. Unless otherwise indicated, the Company owns, directly or indirectly, 100% of the voting securities of all the subsidiaries below.

Name of TPI Subsidiary	Purpose	Jurisdiction of Incorporation	Ownership
TransGlobe West Gharib Inc.	Owns TransGlobe's interest in the West Gharib concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TransGlobe West Bakr Inc.	Owns TransGlobe's interest in the West Bakr concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TG NW Gharib Inc.	Owns TransGlobe's interest in the NW Gharib concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%
TG S Ghazalat Inc.	Owns TransGlobe's interest in the S Ghazalat concession in Egypt.	Turks & Caicos Islands, B.W.I.	100%

Unless the context otherwise requires, reference in this AIF to "TransGlobe" or the "Company" includes the Company and its direct and indirect wholly-owned subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

During the past three years, TransGlobe has developed its business interests through a combination of acquisitions, divestitures, exploration and development.

2016

On December 20, 2016, TransGlobe closed the acquisition of producing and development assets in the Harmattan area of west central Alberta. The acquisition provided the Company with approximately 3,000 boe/d of production (~60% liquids weighted). The acquisition met the Company's strategic objective to diversify and expand operations into lower political risk OECD countries with attractive netbacks to support growth. The assets provided TransGlobe with a stable production base in Canada and potential for significant future growth.

TransGlobe engaged in an active drilling program in 2016, drilling 17 wells in Egypt. The exploration drilling program at NW Gharib, SE Gharib and SW Gharib, consisting of 14 wells in aggregate, yielded two oil discoveries (NWG 27 and NWG 38) and one well with oil shows that was abandoned due to drilling problems (NWG 26). Subsequent to year-end, the Company drilled NWG 26ST (side-track), resulting in a discovery. At the beginning of the year, due to the continuing weakness in oil prices and widening heavy oil differentials, the Company conserved cash and focused on cost cutting initiatives. By mid-spring, in light of some stability returning to oil prices, the Company developed a production recovery plan to recover production that had decreased due to the cash conservation strategy. In addition to the exploration program, the Company drilled two development oil wells at West Bakr and one development oil well at West Gharib as part of the production recovery plan. Capital costs associated with the drilling program trended 30% to 40% below historical norms due to better contract terms and optimized drilling programs, with Red Bed wells (D&A) costing approximately $0.5 million per well versus pre-drill estimates of $0.8 million per well.

Reserves at 2016 year-end were higher compared to 2015 year-end primarily due to the Canadian acquisition and positive revisions of the Arta Red Bed pool performance/technical revisions in addition to positive performance revisions in West Bakr. The Company drilled three development oil wells (two in K-South and one in the Arta Red Bed) during the year. One additional Arta Red Bed development well was drilled and rig released subsequent to December 31, 2016. The Company produced a total of 4.4 MMbbls of crude oil in Egypt in 2016, and production was replaced by the positive technical revisions in the West Gharib and West Bakr concessions. In addition, the Company filed for and received its first development lease in NW Gharib in December. Production from the NWG 3X well commenced prior to year-end 2016, representing a reserve conversion from proved undeveloped to proved producing.

In December 2016, the Company terminated its Borrowing Base Facility. There were no amounts outstanding under the Borrowing Base Facility at the time of termination; however, the Company was utilizing approximately $16.0 million in the form of letters of credit to support its exploration commitments in Egypt. The letters of credit outstanding under the Borrowing Base Facility were transferred to a bilateral letter of credit facility with SMBC. The issued letters of credit under the bilateral letter of credit facility were secured by cash collateral which was on deposit with SMBC. The exploration commitments were fulfilled in 2018.

2017

In 2017, TransGlobe engaged in a drilling program that included a return to Canada, drilling 15 wells in Egypt and three wells in Canada. The exploration drilling program at NW Gharib and SW Gharib, consisting of nine wells in aggregate, yielded two oil discoveries (NWG 26ST and NWG 27ST). The exploration program at South Alamein consisted of one well which was cased, tested and subsequently abandoned. The Company fulfilled its exploration work program commitments in NW Gharib and SW Gharib in 2017. In addition to the exploration program, the Company drilled seven development oil wells and one appraisal oil well in NW Gharib, West Gharib, West Bakr, and Canada resulting in six oil wells.

Reserves at 2017 year-end were lower compared to 2016 year-end primarily due to 2017 production and negative technical revisions of undeveloped Canadian Mannville gas locations. The Company drilled four development oil wells (one in K-South, one in the Arta Red Bed pool, and two in the NW Gharib Red Bed pool) during the year. In addition, the Company filed for and received its second, third and fourth development leases in NW Gharib. In Canada, the Company successfully drilled three development oil wells in the Harmattan area. The Company produced a total of 5.7 MMboe of crude oil, natural gas and natural gas liquids in 2017. One additional Arta Red Bed development well and one K South development well were drilled and rig released subsequent to December 31, 2017.

On February 10, 2017, TransGlobe announced the execution of a $75 million crude oil prepayment agreement between TPI and Mercuria. The prepayment agreement has a term of four years, maturing March 31, 2021, with advances bearing interest at a substantially similar rate as the Company's Debentures at current LIBOR rates. Funding under the prepayment agreement is revolving, with each advance to be satisfied through the delivery of crude oil to Mercuria pursuant to the marketing contract described below. Further advances become available upon delivery of crude oil to Mercuria up to a maximum of $75 million subject to compliance with the terms and conditions of the prepayment agreement including maintenance of a cover ratio which is calculated by dividing the value of forecasted production of crude oil over the applicable period by the outstanding obligations of TPI under the prepayment agreement. If crude oil is not delivered in satisfaction of an advance, the obligations in respect of that advance are ultimately payable in cash. The obligations of TPI under the prepayment agreement and the marketing contract described below are guaranteed by the Company and TPI's subsidiaries, and are supported by, among other things, a pledge of equity held by the Company in TPI and a pledge of equity held by TPI in its subsidiaries.

In conjunction with the prepayment agreement, on February 10, 2017, TPI entered into a marketing contract with Mercuria. Pursuant to the marketing contract, TPI will deliver and Mercuria will market up to 9 million barrels of TPI's crude oil entitlement production from its West Bakr and West Gharib oil fields. Mercuria will receive a per barrel marketing fee, and will use commercially reasonable efforts to achieve the highest and best price for the crude oil delivered under the marketing contract. The pricing of crude oil sales will be based on indexed market prices at the time of sale. Subject to earlier termination of the marketing agreement in accordance with the terms thereof, deliveries of crude oil under the marketing agreement will terminate on the later of: (i) the delivery of 9 million barrels of crude oil; (ii) the prepayment agreement maturity date (March 31, 2021); or (iii) satisfaction of all amounts outstanding under the prepayment agreement.

On May 16, 2017, TransGlobe announced it had entered into a credit agreement for an RBL with ATB. Pursuant to the credit agreement, the RBL commitment is up to a maximum of C$30 million. The amount available to be drawn on the RBL will be dependent upon the borrowing base, which is determined with reference to the Company’s proved oil and gas reserves in Canada, as evaluated in the most recent annual reserve report(s) and delivered pursuant to the credit agreement. As of the closing date, the borrowing base was set at C$30 million. TransGlobe initially used the funds available under

the RBL to repay the existing C$15 million vendor-take-back loan outstanding, which had an interest rate of 10% per annum. Additional funds were allocated as necessary to carry out the Company's capital expenditure program in Canada.

2018

TransGlobe's 2018 drilling program included drilling eight development oil wells in Egypt (two in Arta, two in NW Gharib, two in K-South, and two in M-field) and four exploration wells (two in NW Sitra, two in South Ghazalat). In Canada, the Company successfully drilled six gross (five net) development oil wells in the Harmattan area.

2P reserves at year-end 2018 were 4% lower than 2017 primarily due to production of ~5.3 mmboe, substantially offset by net positive revisions of ~3.5 MMboe. The net positive revisions reflect additions from a discovery at South Ghazalat, extensions at West Bakr, improved recovery in Egypt, and infill drilling in Canada, offset by a negative revision related to minor asset performance in Egypt and economic factors in Canada.

TransGlobe produced an average of 14,439 boe/d in 2018 (2017 – 15,506 boe/d). Egypt production was 12,150 bbls/day in 2018 (2017 - 12,822 bbls/d) and Canada production was 2,289 boe/d (2017 - 2,684 boe/d).

The Board approved the reinstatement of the dividend payments in 2018. The Company will aspire to pay a semi-annual dividend to Shareholders determined at each period after consideration for: (i) ongoing production maintenance; (ii) growth through acquisitions; (iii) maintaining a conservative balance sheet to manage commodity price volatility; (iv) payment irregularity in Egypt and solvency requirements; and (v) the cash flow generating capability of the business. In August 2018, the Board approved a dividend payment to Shareholders of $0.035/Common Share payable on September 14, 2018.

Recent Developments

Mr. Ross Clarkson retired as Chief Executive Officer of the Company effective December 31, 2018. Mr. Clarkson led the company for 22 years as it grew and developed resources in Egypt, Yemen and Canada. Mr. Clarkson will remain on the Board as a non-executive director. TransGlobe's current President, Randy Neely, was appointed as Chief Executive Officer and President of the Company effective January 1, 2019.

Further, Mr. Fred Dyment retired from the Board of Directors on December 31, 2018. Mr. Dyment was an independent non-executive director of the Company since 2004 while acting as member of the Company's Audit Committee and CHR&G Committee. Following the retirement of Mr. Dyment, the Company appointed Dr. Carol Bell of London, England as an independent non-executive director effective January 1, 2019.

Brett Norris, Vice President Exploration, ceased to be employed with the Company on January 4, 2019.

During the latter half of 2018, the Company initiated a search for a Chief Operating Officer to replace Lloyd Herrick, who had informed the Company that he plans to retire in early 2020. Following a robust search, the Company recruited Geoffrey (Geoff) Probert for the position of Vice President and Chief Operating Officer. It is expected that Geoff will join the Company on March 18, 2019, at which time Lloyd Herrick will transition to the position of Executive Vice President to provide Chief Operating Officer transition and support growth initiatives.

Effective March 12, 2019, the Company appointed Edward LeFehr of Alberta, Canada to the Board as an independent non-executive director. Further, effective March 12, 2019 Bob MacDougall resigned from the Board of Directors of the Company. Mr. MacDougall served for four years as Chair of the RHSE&S Committee. Finally, at the upcoming annual general and special meeting of the Shareholders Robert Jennings and Matt Brister will be retiring and will not stand for reelection.

In March 2019, the Board approved a dividend payment to Shareholders of $0.035/Common Share payable on April 18, 2019.

Significant Acquisitions

TransGlobe did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS AND PRINCIPAL PROPERTIES

General

TransGlobe is engaged in the exploration, development and production of crude oil and natural gas in Egypt and Canada. The Company also regularly reviews potential acquisitions and new international exploration blocks to supplement its exploration and development activities.

TransGlobe has had operations in Egypt during the past 14 years. The Company also operated in Canada from 1999 to 2008, and made a re-entry into Canada in December 2016. In Egypt, the Company currently has an interest in five PSCs: West Gharib, West Bakr, South Alamein, NW Gharib, and South Ghazalat. In Canada, the Company owns production and working interests in certain facilities in the Cardium light oil and Mannville liquid-rich gas assets in the Harmattan area of west central Alberta.

A significant portion of the Company's operations occur outside of Canada and therefore are subject to political and regulatory risk in those other jurisdictions. See "*Risk Factors*".

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including in Egypt and Canada where the Company's assets, activities, and employees are located. Operators more established than the Company, with access to broader technical skills, larger amounts of capital and other resources, and are active in the industry in Egypt and Canada, where the Company has operations. This represents a significant risk for the Company, which must rely on modest resources as compared to some of its competitors. See "*Risk Factors*".

Environmental Protection

The Company operates under the jurisdiction of a number of regulatory bodies and agencies that set forth numerous prohibitions and requirements with respect to planning and approval processes related to land use, sustainable resource management, waste management, responsibility for the release of presumed hazardous materials, protection of wildlife, and the environment and the health and safety of workers. Legislation provides for restrictions and prohibitions on the transport of dangerous goods and the release or emission of various substances, including substances used and produced in association with certain oil and gas industry operations. The legislation addresses various permits, including for drilling, well completion, installation of surface equipment, air monitoring, surface and ground water monitoring in connection with these activities, waste management and access to remote or environmentally sensitive areas.

Historically, environmental protection requirements have not had a significant financial or operational effect on TransGlobe's capital expenditures, earnings or competitive position. Subject to any changes in current environmental protection legislation, or in the way the legislation is interpreted in the jurisdictions in which it operates, TransGlobe does not presently anticipate environmental protection requirements will have a significant effect on such matters in 2019. The Company is exposed to potential environmental liability in connection with its business of oil and gas exploration and production. See "*Risk Factors*".

Social or Environmental Policies

The Company's RHSE&S Committee reviewed and approved fundamental policies pertaining to health, safety, environment and social responsibility which have the potential to impact the Company's activities and strategies. The RHSE&S Committee reported to the Board on TransGlobe's performance with respect to applicable laws, regulations and Company policies and also in respect to emerging trends, issues and regulations related to health, safety and environment. The RHSE&S Committee is comprised of a majority of independent directors and continues to report to the Board on TransGlobe's performance with respect to applicable laws, regulations and Company policies and also in respect to emerging trends, issues and regulations related to health, safety and environment.

Specialized Skill and Knowledge

TransGlobe employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial, accounting and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, TransGlobe believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows TransGlobe to effectively identify, evaluate and execute on its business plan.

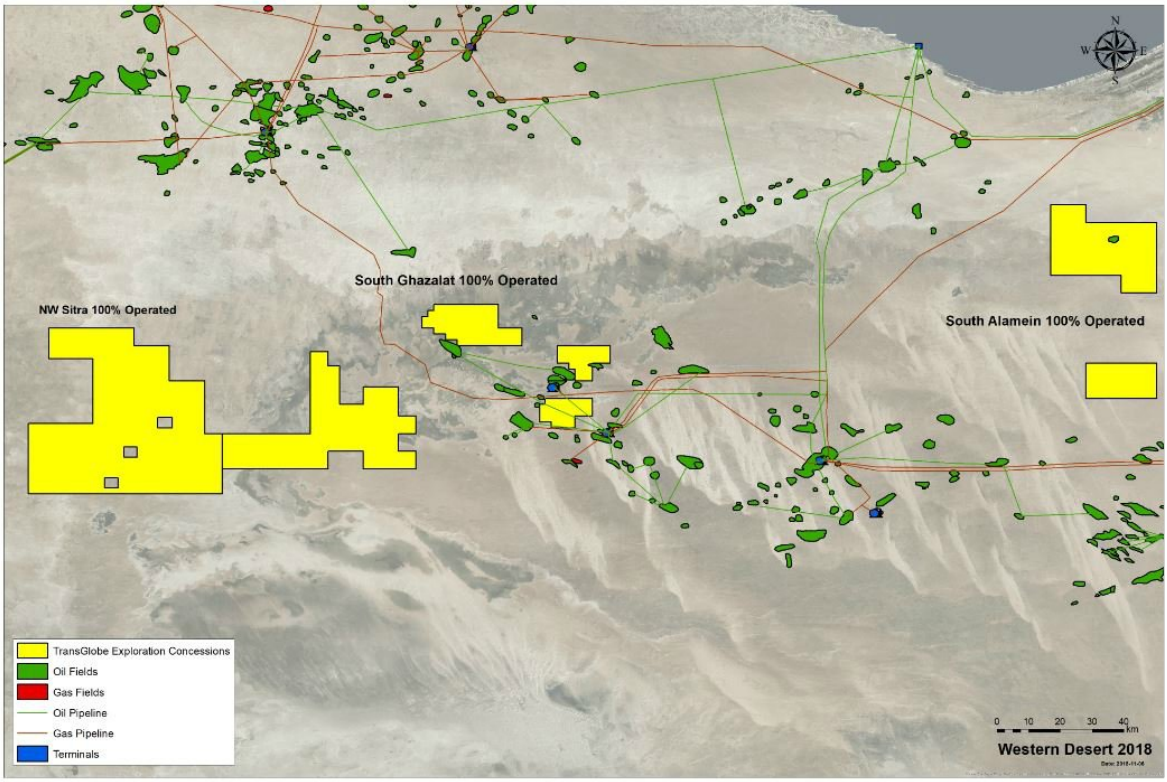
Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to fix netbacks on production volumes. See "Other Oil and Gas Information - Forward Contracts" for our current hedging program.

Egypt Business Unit

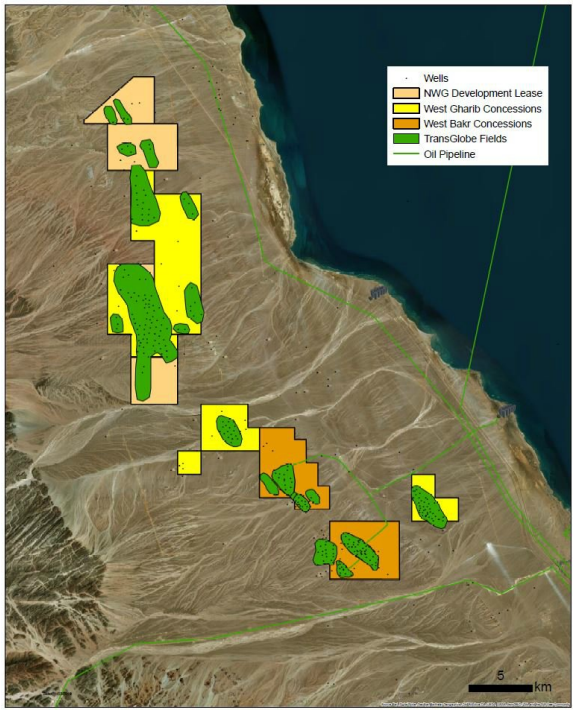
Summary of International Land Holdings as at December 31, 2018

Western Desert, Egypt[1]



1 On January 7, 2019, the Company relinquished its interest in the NW Sitra concession.

Eastern Desert, Egypt



Summary of International PSC Terms

All of the Company's international blocks are PSCs between the host government and the contractor. The government and the contractors take their share of production based on the terms and conditions of the respective contracts. The contractors' share of all taxes and royalties are paid out of the government's share of production.

The PSCs provide for the government to receive a percentage gross royalty on the gross production. The remaining oil production, after deducting the gross royalty, if any, is split between cost sharing oil and production sharing oil. Cost sharing oil is up to a maximum percentage as defined in the specific PSC. Cost oil is assigned to recover approved operating and capital costs spent on the specific project. Unutilized cost sharing oil or excess cost oil (maximum cost recovery less actual cost recovery) is shared between the government and the contractor as defined in the specific PSCs. Each PSC is treated individually in respect of cost recovery and production sharing purposes. The remaining production sharing oil (total production, less gross royalty, less cost oil) is shared between the government and the contractor as defined in the specific PSCs.

The following tables summarize the Company's international PSC terms for the first tranche(s) of production for each block. All of the contracts have different terms for production levels above the first tranche, which are unique to each contract. The government's share of production increases and the contractor's share of production decreases as the production volumes go to the next production tranche. TransGlobe is the operator of, and has a 100% working interest in, all PSCs.

EASTERN DESERT - GULF OF SUEZ BASIN - EGYPT

Block	West Gharib	West Bakr	NW Gharib
Year acquired	2007	2011	2013
Block Area (acres)	22,725	11,143	11,199
Expiry date	2019-2026	2020	Dec 2036
Extensions			
Exploration	N/A	N/A	N/A
Development	+ 5 years	+ 5 years	+ 5 years
Production Tranche (mbopd)	0-5	0-50	0-5
Max. cost oil	30%	30%	25%
Excess cost oil			
Contractor	30%	0%	5%
Depreciation per quarter			
Operating	100%	100%	100%
Capital	6%	5%	5%
Production Sharing Oil:			
Contractor	30%	15%	15%
Government	70%	85%	85%

WESTERN DESERT - WESTERN DESERT BASIN - EGYPT[1]

Block	South Alamein	S Ghazalat
Year acquired	2012	2013
Block Area (acres)	197,807	349,313
Expiry date	January 2019[2]	May 2019[3]
Extensions		
Exploration	N/A	2 years
Development	20 + 5 years	20 + 5 years
Production Tranche (mbopd)	0-5	0-5
Max. cost oil	30%	25%
Excess cost oil		
Contractor	0%	5%
Depreciation per quarter		
Operating	100%	100%
Capital	5%	5%
Production Sharing Oil:		
Contractor	14%	17%
Government	86%	83%

[1] On January 7, 2019, the Company relinquished its interest in the NW Sitra concession, therefore the concession terms are not included in the above table.

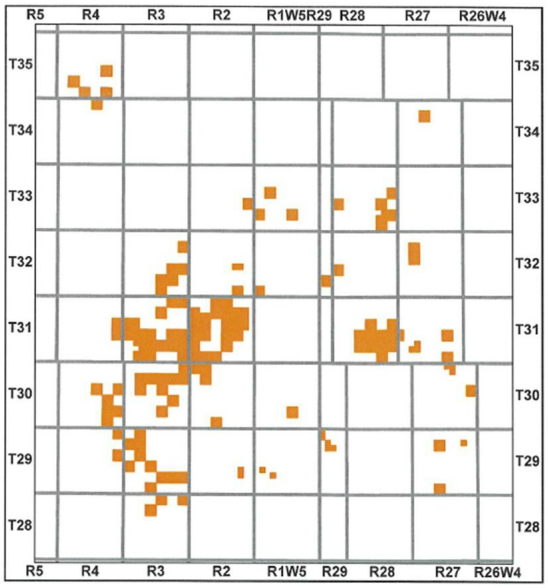
[2] The South Alamein concession is in the second two-year extension period which was due to expire on April 5, 2014. EGPC put certain areas within the concession on hold as of July 2012, pending access by the contractor. All work commitments have been fulfilled. In Q2-2018 the Company received a seven-month extension to the final exploration phase, which was set to expire January 26, 2019. In January 2019, the Company submitted an extension request and has entered into extension discussions with EGPC. The Company has resubmitted a request for military access to drill the SA 24X Jurassic exploration prospect.

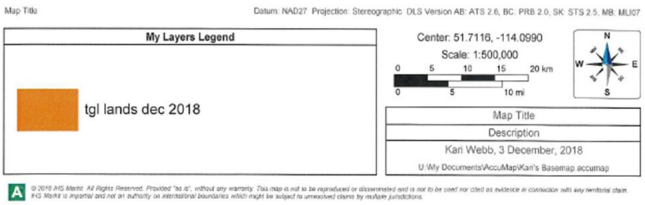
[3] In 2018, the Company submitted a declaration of commercial oil well discovery for the SGZ 6X discovery. In February 2019, the Company submitted a development plan for the SGZ 6X discovery to begin development discussions with EGPC.

The West Bakr PSC contains rights on the part of Egypt to take in kind from the Company, its share of the profit oil entitlement (but not cost oil entitlement) at the market price, but only for operating requirements of refineries. The West Gharib PSC contains rights on the part of Egypt to purchase from the Company, but only for the requirements of the Egyptian market, the Company's profit oil entitlement (but not cost oil entitlement), proportional to the aggregate of Egypt's contractual rights, at the market price. None of the Egyptian PSCs contain minimum production or sales requirements, and there are no restrictions with respect to pricing of the Company's sales volumes. Except as otherwise disclosed in this AIF, all crude oil sales are priced at current market rates at the time of sale.

Canada Business Unit

Alberta, Canada





In Canada, the Company drilled six gross (five net) horizontal Cardium development wells in 2018 from a common pad to improve efficiencies and reduce costs. In 2018, the Company drilled and completed five one-mile horizontal wells and the Company's first two-mile horizontal well. The wells were fracture stimulated during November and December and equipped to produce by year end. In addition, the Company completed construction of a new oil gathering pipeline to connect the new multi-well pad and two existing producers to the Company s main oil processing facility to reduce trucking in the community and associated operating expenses. The 2018 drilling program focused on reserve conversions, moving the reserves from the undeveloped to developed categories.

2019 Outlook Highlights

- Production is expected to average between 14,000 and 15,000 boe/d in 2019 (mid-point of 14,500 boe/d); and
- Exploration and development spending is budgeted to be $34.1 million (before capitalized G&A) and includes $24.1 million for Egypt and $10.0 million (C$13.0 million) for Canada, to be funded from cash flow and working capital.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The report on reserves data in Form 51-101F2 and the report of management and directors on oil and gas disclosure in Form 51-101F3 are attached as Schedules "A" and "B", respectively, to this AIF, which forms are incorporated herein by reference.

The statement of reserves data and other oil and gas information set forth below GLJ Report is dated January 22, 2019, with the effective date being December 31, 2018.

Disclosure of Reserves Data

All of the Company's reserves herein reported were evaluated by independent evaluators in accordance with NI 51-101 for the year ended December 31, 2018. In 2018, GLJ, independent petroleum engineering consultants based in Calgary, Alberta, were retained by the Company's RHSE&S Committee to independently evaluate 100% of TransGlobe's reserves as at December 31, 2018.

The reserves data set forth below (the "**Reserves Data**") was prepared by GLJ with an effective date of December 31, 2018 and December 31, 2017, respectively. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The Company reports in U.S. currency and therefore the reports have been converted to U.S. dollars at the prevailing conversion rate at December 31 of the respective years. See "*Currency and Exchange Rates*". All of the Company's reserves are located in the province of Alberta, Canada and Egypt.

The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. The Reserves Data conforms to the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Company believes is important to the readers of this information.

All evaluations and reviews of future net revenue are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net revenue shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery, and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Company's properties may vary from the information presented herein and such variations could be material. In addition, there is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The information relating to the Company's reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs and anticipated production. See "*Forward-Looking Statements*" and "*Risk Factors*".

Possible reserves are those additional reserves that are less certain to be recovered than probable resources. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Reserves Data – Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
TOTAL COMPANY
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Light Crude Oil & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total bbls	
By Category	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (Bcf)	Net[2] (Bcf)	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (MMboe)	Net[2] (MMboe)
Proved										
Developed producing	2.4	1.8	10.4	5.7	14.4	11.7	2.3	1.7	17.6	11.2
Developed non-producing	1.1	0.8	1.9	1.0	2.0	1.8	0.3	0.3	3.7	2.4
Undeveloped	2.3	2.0	1.8	0.9	5.2	4.7	0.8	0.7	5.8	4.4
Total Proved	**5.9**	**4.6**	**14.0**	**7.6**	**21.6**	**18.1**	**3.4**	**2.7**	**26.9**	**17.9**
Probable	3.9	2.8	8.0	4.0	16.5	14.9	2.6	2.3	17.2	11.6
Proved+Probable	**9.7**	**7.4**	**22.1**	**11.6**	**38.1**	**33.0**	**6.0**	**4.9**	**44.1**	**29.5**
Possible	3.8	2.5	8.9	4.3	16.9	14.9	2.2	1.9	17.8	11.2
Proved+Probable+ Possible	**13.5**	**10.0**	**31.0**	**15.9**	**55.0**	**47.9**	**8.3**	**6.8**	**62.0**	**40.7**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.

[2] Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Egypt include the Company's share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.

SUMMARY OF OIL AND GAS RESERVES
EGYPT
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Light Crude Oil & Medium Crude Oil		Heavy Crude Oil		Total bbls	
By Category	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (MMbbls)	Net[2] (MMbbls)
Proved						
Developed producing	1.2	0.8	10.4	5.7	11.6	6.5
Developed non-producing	0.3	0.2	1.9	1.0	2.2	1.2
Undeveloped	0.4	0.2	1.8	0.9	2.1	1.2
Total Proved	**1.9**	**1.2**	**14.0**	**7.6**	**15.9**	**8.8**
Probable	1.8	1.1	8.0	4.0	9.8	5.1
Proved+Probable	**3.6**	**2.3**	**22.1**	**11.6**	**25.7**	**13.8**
Possible	2.4	1.4	8.9	4.3	11.3	5.7
Proved+Probable+ Possible	**6.1**	**3.7**	**31.0**	**15.9**	**37.0**	**19.6**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.

[2] Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Egypt include the Company's share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.

SUMMARY OF OIL AND GAS RESERVES
CANADA
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total bbls	
By Category	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (Bcf)	Net[2] (Bcf)	Gross[1] (MMbbls)	Net[2] (MMbbls)	Gross[1] (MMboe)	Net[2] (MMboe)
Proved								
Developed producing	1.2	1.0	14.4	11.7	2.3	1.7	5.9	4.7
Developed non-producing	0.8	0.7	2.0	1.8	0.3	0.3	1.4	1.2
Undeveloped	2.0	1.8	5.2	4.7	0.8	0.7	3.6	3.2
Total Proved	**4.0**	**3.5**	**21.6**	**18.1**	**3.4**	**2.7**	**11.0**	**9.2**
Probable	2.0	1.7	16.5	14.9	2.6	2.3	7.4	6.5
Proved+Probable	**6.0**	**5.2**	**38.1**	**33.0**	**6.0**	**4.9**	**18.4**	**15.6**
Possible	1.4	1.1	16.9	14.9	2.2	1.9	6.4	5.4
Proved+Probable+ Possible	**7.4**	**6.3**	**55.0**	**47.9**	**8.3**	**6.8**	**24.8**	**21.1**

[1] Gross reserves are the Company's working interest share before the deduction of royalties.

[2] Net reserves are the Company's working interest share after the deduction of royalties.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
TOTAL COMPANY
AS OF DECEMBER 31, 2018
(FORECAST PRICES & COSTS)

The estimated future net revenues presented in the tables below do not represent fair market value. The estimated future net revenues presented below are calculated using the price forecasts and inflation rates set forth below under "*Pricing Assumptions*".

US$	Before Income Tax[1] Discounted at %/yr					After Income Tax[1] Discounted at %/yr					Unit Value Before Tax[1] (discounted at 10%/year)
$MM	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/bbl)
Proved											
Developed producing	177.1	154.8	137.7	124.4	113.8	177.1	154.8	137.7	124.4	113.8	12.34
Developed non-producing	62.0	50.6	42.8	37.2	33.1	62.0	50.6	42.8	37.2	33.1	17.81
Undeveloped	101.4	69.6	50.4	38.0	29.5	88.9	62.6	46.3	35.5	28.0	11.57
Total Proved	**340.5**	**275.0**	**231.0**	**199.7**	**176.4**	**328.0**	**268.0**	**226.9**	**197.2**	**174.8**	**12.88**
Probable	241.9	153.7	108.1	81.8	65.1	204.5	133.9	96.4	74.3	60.0	9.36
Total Proved+Probable	**582.4**	**428.7**	**339.1**	**281.4**	**241.5**	**532.5**	**401.9**	**323.3**	**271.5**	**234.8**	**11.50**
Possible	258.0	155.4	107.1	80.5	64.1	223.6	138.8	97.5	74.3	59.8	9.59
Total Proved+Probable +Possible	**840.3**	**584.1**	**446.2**	**361.9**	**305.5**	**756.1**	**540.7**	**420.8**	**345.8**	**294.6**	**10.98**

[1] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
EGYPT
AS OF DECEMBER 31, 2018
(FORECAST PRICES & COSTS)

US$	Before Income Tax[1] Discounted at %/yr					After Income Tax[1] Discounted at %/yr					Unit Value Before Tax[1] (discounted at 10%/year)
$MM	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/bbl)
Proved											
Developed producing	126.5	113.8	103.8	95.7	89.1	126.5	113.8	103.8	95.7	89.1	16.08
Developed non-producing	22.0	19.4	17.3	15.6	14.2	22.0	19.4	17.3	15.6	14.2	14.96
Undeveloped	25.0	21.7	19.1	16.9	15.2	25.0	21.7	19.1	16.9	15.2	16.58
Total Proved	**173.5**	**155.0**	**140.2**	**128.3**	**118.4**	**173.5**	**155.0**	**140.2**	**128.3**	**118.4**	**16.00**
Probable	103.2	81.3	66.4	55.7	47.8	103.2	81.3	66.4	55.7	47.8	13.10
Total Proved+Probable	**276.7**	**236.3**	**206.7**	**184.0**	**166.2**	**276.7**	**236.3**	**206.7**	**184.0**	**166.2**	**14.94**
Possible	131.4	94.6	72.6	58.3	48.5	131.4	94.6	72.6	58.3	48.5	12.68
Total Proved+Probable +Possible	**408.1**	**330.9**	**279.2**	**242.3**	**214.7**	**408.1**	**330.9**	**279.2**	**242.3**	**214.7**	**14.28**

[1] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
CANADA
AS OF DECEMBER 31, 2018
(FORECAST PRICES & COSTS)

US$	Before Income Tax Discounted at %/yr					After Income Tax Discounted at %/yr					Unit Value Before Tax (discounted at 10%/year)
$MM	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/bbl)
Proved											
Developed producing	50.6	41.0	33.9	28.7	24.7	50.6	41.0	33.9	28.7	24.7	7.21
Developed non-producing	40.0	31.1	25.5	21.6	18.9	40.0	31.1	25.5	21.6	18.9	20.46
Undeveloped	76.4	47.9	31.3	21.1	14.4	63.9	40.9	27.2	18.6	12.8	9.77
Total Proved	**167.0**	**120.0**	**90.7**	**71.4**	**58.0**	**154.5**	**113.1**	**86.6**	**68.9**	**56.4**	**9.91**
Probable	138.7	72.4	41.7	26.0	17.3	101.3	52.5	30.0	18.5	12.2	6.43
Total Proved+Probable	**305.7**	**192.4**	**132.5**	**97.4**	**75.2**	**255.8**	**165.6**	**116.6**	**87.4**	**68.6**	**8.47**
Possible	126.6	60.8	34.5	22.2	15.6	92.2	44.2	25.0	16.1	11.3	6.34
Total Proved+Probable +Possible	**432.2**	**253.2**	**167.0**	**119.6**	**90.8**	**348.0**	**209.8**	**141.6**	**103.5**	**79.9**	**7.92**

TOTAL FUTURE NET REVENUE[3]
(UNDISCOUNTED)
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

Reserves Category	Revenue (US$MM)	Royalties (US$MM)	Operating Costs[1] (US$MM)	Development Costs (US$MM)	Abandonment and Reclamation Costs[2] (US$MM)	Future Net Revenue Before Income Taxes[1] (US$MM)	Income Taxes[1] (US$MM)	Future Net Revenue After Income Taxes[1] (US$MM)
Proved Reserves								
Canada	440.1	67.3	151.5	43.7	10.7	167.0	12.5	154.5
Egypt	894.3	493.5	216.1	11.1	—	173.5	—	173.5
Total Company	1,334.4	560.8	367.6	54.8	10.7	340.5	12.5	328.0
Proved+Probable Reserves								
Canada	765.2	109.3	246.1	90.3	13.9	305.7	49.8	255.8
Egypt	1,508.5	849.0	361.7	21.0	—	276.7	—	276.7
Total Company	2,273.7	958.3	607.8	111.4	13.9	582.4	49.8	532.5
Proved+Probable+ Possible Reserves								
Canada	1,043.8	153.9	330.2	111.3	16.1	432.2	84.2	348.0
Egypt	2,258.2	1,291.3	531.4	27.4	—	408.1	—	408.1
Total Company	3,302.0	1,445.2	861.6	138.7	16.1	840.3	84.2	756.1

[1] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax. Income taxes payable in Egypt have been recorded as Operating Costs for reporting purposes. In Canada, operating costs are net of processing and other income.

[2] Please see "*Additional Information Concerning Abandonment and Reclamation Costs*" below.

[3] Values are calculated by considering existing tax pools for the Company in the evaluation of the Company's properties and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see the Company's financial statements and management's discussion and analysis for the year ended December 31, 2018.

NET PRESENT VALUE OF FUTURE NET REVENUES
BY PRODUCT TYPE
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

Reserves Category	Product Type	Future net Revenue Before Taxes[3,4] (discounted at 10%/year) (US$MM)	Unit Value Before Tax[3,4] (discounted at 10%/year) ($/bbl)
Total Proved	Light Crude Oil and Medium Crude Oil[1]	115.9	14.98
	Heavy Crude Oil[1]	119.3	15.79
	Conventional Natural Gas[2]	(4.2)	(1.60)
Proved+Probable	Light Crude Oil and Medium Crude Oil[1]	164.6	13.83
	Heavy Crude Oil[1]	172.2	14.91
	Conventional Natural Gas[2]	2.3	0.38
Proved+Probable +Possible	Light Crude Oil and Medium Crude Oil[1]	210.7	13.75
	Heavy Crude Oil[1]	224.9	14.16
	Conventional Natural Gas[2]	10.6	1.12

[1] Including solution gas and other by-products.

[2] Including by-products but excluding solution gas.

[3] Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

[4] In Egypt, under the terms of the PSCs, income tax is current and assessed on all production sharing oil; therefore all Egypt future net revenues are after income tax.

1. Columns may not add due to rounding.

2. The crude oil, NGLs and natural gas reserve estimates presented in the Reserves Data are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling Exploratory Wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to as "prospecting" costs) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping Exploratory Wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(c) **Possible reserves** are those additional reserves that are even less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will be greater than the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.

Each of the reserve categories (proved, probable and possible) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(b) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(c) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(i) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

(ii) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and

(iii) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5 of the COGE Handbook.

Pricing Assumptions

Forecast Prices and Costs

The forecast cost and price assumptions assume changes in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

For the reserves, crude oil benchmark reference pricing, as at December 31, 2018, inflation and exchange rates utilized by GLJ in the Reserves Data, which were GLJ's then current forecasts at the date of the Reserves Data, were as follows:

Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40 API (C$/bbl)	Brent Reference Price (US$/bbl)	AECO Gas Price (C$/MMBtu)	Ethane (C$/bbl)	Propane (C$/bbl)	Butane (C$/bbl)	Pentane (C$/bbl)	Inflation Rates[1] %/Year	Exchange Rate (C$/US$)
Forecast										
2019	56.25	63.33	63.25	1.85	5.69	25.33	21.45	67.67	—	0.75
2020	63.00	75.32	68.50	2.29	7.20	32.39	37.66	79.22	2.0	0.77
2021	67.00	79.75	71.25	2.67	8.51	36.68	47.85	83.54	2.0	0.79
2022	70.00	81.48	73.00	2.90	9.27	39.11	57.04	85.49	2.0	0.81
2023	72.50	83.54	75.50	3.14	10.12	41.77	58.48	87.80	2.0	0.82
2024	75.00	86.06	78.00	3.23	10.42	43.03	60.24	90.30	2.0	0.83
2025	77.50	89.09	80.50	3.34	10.78	44.55	62.36	93.33	2.0	0.83
2026	80.41	92.62	83.41	3.41	11.03	46.31	64.83	96.86	2.0	0.825
2027	82.02	94.57	85.02	3.48	11.27	47.28	66.20	98.81	2.0	0.825
2028	83.66	96.56	86.66	3.54	11.48	48.28	67.59	100.80	2.0	0.825
Thereafter		Escalate oil, gas and product prices at 2.0% per year thereafter							+2.0%/year	+0%/year

[1] Inflation rates for forecasting expenditure prices and costs.

The weighted average historical price in US$ realized by the Company in Egypt, for the year ended December 31, 2018 for crude oil was $59.88/bbl.

The weighted average historical price in US$ realized by the Company in Canada, for the year ended December 31, 2018 for crude oil and natural gas liquids was $52.37/bbl and $27.17/bbl, respectively, and for conventional natural gas was $1.26/Mcf.

Reconciliation of Changes in Reserves

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
TOTAL COMPANY
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Light Crude Oil & Medium Crude Oil			Heavy Crude Oil		
Factors	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2017	6.3	3.8	10.1	13.9	9.0	22.8
Discoveries	0.1	0.4	0.4	—	—	—
Extensions and improved recovery	0.2	(0.1)	0.1	2.6	0.8	3.5
Technical revisions	(0.2)	(0.3)	(0.5)	1.7	(1.8)	(0.1)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	(0.6)	—	(0.6)	(4.1)	—	(4.1)
December 31, 2018	**5.8**	**3.8**	**9.6**	**14.0**	**8.0**	**22.1**

	Conventional Natural Gas			Natural Gas Liquids		
Factors	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2017	22.9	17.4	40.3	3.5	2.7	6.2
Discoveries	—	—	—	—	—	—
Extensions and improved recovery	0.2	(0.2)	—	—	—	—
Technical revisions	0.8	(0.5)	0.3	0.2	—	0.1
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(0.2)	(0.2)	(0.4)	—	—	—
Production	(2.1)	—	(2.1)	(0.3)	—	(0.3)
December 31, 2018	**21.6**	**16.5**	**38.1**	**3.4**	**2.6**	**6.0**

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
EGYPT
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Light Crude Oil & Medium Crude Oil			Heavy Crude Oil		
Factors	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2017	2.3	1.5	3.8	13.9	9.0	22.8
Discoveries[1]	0.1	0.4	0.4	—	—	—
Extensions and improved recovery[2]	—	—	—	2.6	0.8	3.5
Technical revisions[3]	(0.1)	(0.2)	(0.3)	1.7	(1.8)	(0.1)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	(0.3)	—	(0.3)	(4.1)	—	(4.1)
December 31, 2018	**1.9**	**1.8**	**3.6**	**14.0**	**8.0**	**22.1**

[1] Attributed to South Ghazalat discovery of SGZ 6X.

[2] Attributed to infill drilling at M Field and NW Gharib.

[3] Attributed to production optimization in West Bakr primarily in K Field.

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
CANADA
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

	Conventional Natural Gas			Light Crude Oil & Medium Crude Oil		
Factors	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2017	22.9	17.4	40.3	4.1	2.2	6.3
Discoveries	—	—	—	—	—	—
Extensions and improved recovery[1]	0.2	(0.2)	—	0.2	(0.1)	0.1
Technical revisions[2]	0.8	(0.5)	0.3	(0.1)	(0.1)	(0.2)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(0.2)	(0.2)	(0.4)	—	—	—
Production	(2.1)	—	(2.1)	(0.2)	—	(0.2)
December 31, 2018	**21.6**	**16.5**	**38.1**	**4.0**	**2.0**	**6.0**

[1] Attributed to infill drilling in Harmattan.

[2] Attributed to improved performance of the 2017 horizontal wells.

	Natural Gas Liquids		
Factors	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)
December 31, 2017	3.5	2.7	6.2
Discoveries	—	—	—
Extensions and improved recovery	—	—	—
Technical revisions[1]	0.2	—	0.1
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Production	(0.3)	—	(0.3)
December 31, 2018	**3.4**	**2.6**	**6.0**

[1] Positive technical revisions primarily attributed to improved performance of the 2017 horizontal wells.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves are planned to be developed over the next two years.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*" herein.

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to the Company in the most recent three financial years.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (MMbbl)		Heavy Crude Oil (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2016[1]	1.7	2.0	1.0	3.0
2017[2]	0.7	2.8	0.2	1.4
2018[3]	0.1	2.4	0.8	1.8

[1] In 2016, proved undeveloped reserves were assigned to Egypt's Arta Red Bed development program in West Gharib. The acquisition of oil and gas reserves in Canada in the Harmattan area carry the balance of first attributed oil and gas reserves.

[2] In 2017, proved undeveloped reserves were assigned to Egypt's NW Gharib Red Bed development program and to Canada's Cardium development program.

[3] In 2018, proved undeveloped reserves were assigned to Egypt's NW Gharib and South Ghazalat development programs.

Year	Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2016[1]	9.0	9.0	1.7	1.7
2017[2]	1.7	6.4	0.3	1.0
2018[3]	—	5.2	—	0.8

[1] In 2016, proved undeveloped reserves were assigned to Egypt's Arta Red Bed development program in West Gharib. The acquisition of oil and gas reserves in Canada in the Harmattan area carry the balance of first attributed oil and gas reserves.

[2] In 2017, proved undeveloped reserves were assigned to Egypt's NW Gharib Red Bed development program and to Canada's Cardium development program.

[3] In 2018, no new proved undeveloped reserves were assigned.

A total of 5.2 Bcf of conventional natural gas, 2.4 MMbbl of light crude oil and medium crude oil, 1.8 MMbbl of heavy crude oil and 0.8 MMbbl of NGLs were assigned in the GLJ Report under forecast prices and costs as gross proved undeveloped reserves as at December 31, 2018, representing approximately 21% of total proved reserves, together with $54.8 million of associated undiscounted future capital expenditures. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data.

The capital associated with developing proved undeveloped reserves in the GLJ Report is expected to be spent between 2019 and 2022, with approximately 36% of the capital scheduled to be spent through 2019 and 30% scheduled to be spent through 2020. Although TransGlobe expects the development of the proved undeveloped reserves attributed to the Company's assets to be consistent with that set out above, current industry conditions and other uncertainties as discussed under "*Risk Factors*" and "*Industry Conditions*" herein could result in development of such proved undeveloped reserves on a different schedule than set out above.

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (MMbbl)		Heavy Crude Oil (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2016[1]	1.1	1.2	0.7	3.1
2017[2]	0.6	2.0	0.6	3.4
2018[3]	0.4	2.1	0.3	1.9

[1] In 2016, probable undeveloped reserves were assigned to Egypt's Arta Red Bed development program in West Gharib. The acquisition of oil and gas reserves in Canada in the Harmattan area carry the balance of first attributed oil and gas reserves.

[2] In 2017, probable undeveloped reserves were assigned to Egypt's NW Gharib Red Bed development program and to Canada's Cardium development program.

[3] In 2018, probable undeveloped reserves were assigned to Egypt's NW Gharib and South Ghazalat development programs.

Year	Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2016[1]	19	19	3.3	3.3
2017[2]	1.5	13.5	0.2	2.1
2018[3]	—	12.5	—	2.0

[1] In 2016, probable undeveloped reserves were assigned to Egypt's Arta Red Bed development program in West Gharib. The acquisition of oil and gas reserves in Canada in the Harmattan area carry the balance of first attributed oil and gas reserves.

[2] In 2017, probable undeveloped reserves were assigned to Egypt's NW Gharib Red Bed development program and to Canada's Cardium development program.

[3] In 2018, no new probable undeveloped reserves were assigned.

A total of 12.5 Bcf of conventional natural gas, 2.1 MMbbl of light crude oil and medium crude oil, 1.9 MMbbl of heavy crude oil and 2.0 MMbbl of NGLs were assigned in the GLJ Report under forecast prices and costs as gross probable undeveloped reserves as at December 31, 2018, representing approximately 47% of total probable reserves, together with $56.6 million of associated undiscounted future capital expenditures. The probable undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data.

The capital associated with developing probable undeveloped reserves in the GLJ Report is expected to be spent between 2019 and 2024, with approximately 16% of the capital scheduled to be spent through 2019 and 8% scheduled to be spent through 2020. Although TransGlobe expects the development of the probable undeveloped reserves attributed to the Company's assets to be consistent with that set out above, current industry conditions and other uncertainties as discussed under "*Risk Factors*" and "*Industry Conditions*" herein could result in development of such probable undeveloped reserves on a different schedule than set out above.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, commodity prices, reservoir performance, governmental restrictions, economic conditions, geologic conditions or production. These revisions can be either positive or negative. See "*Risk Factors*".

Changes in future commodity prices relative to the forecasts described above under "*Pricing Assumptions*" could have a negative impact on the reserves associated with the Company's assets, and in particular on the development of undeveloped reserves, unless future development costs are adjusted in parallel. The Company's assets include a significant amount of proved and probable undeveloped reserves. At the forecast prices and costs used in the GLJ Report, these development activities are expected to be economic. However, should oil and natural gas prices decrease materially, these activities may need to be deferred to ensuing years to remain economic or may not be pursued at all. Other than the foregoing and the factors disclosed or described herein, the Company does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of the reserves data in respect of the Company's assets.

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to: (i) proved reserves (in total) estimated using forecast prices and costs; and (ii) proved plus probable reserves (in total) estimated using forecast prices and costs.

Future Development Costs

FUTURE DEVELOPMENT COSTS
TOTAL COMPANY
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

(US$MM)	Forecast Prices and Costs	
Year	Proved Reserves	Proved Plus Probable Reserves
2019	19.8	29.0
2020	16.6	21.2
2021	10.2	12.1
2022	8.2	23.3
2023	—	11.3
Remaining	—	14.4
Total Undiscounted	54.8	111.4
Discounted at 10%	47.2	88.2

To fund its capital program, including future development costs, the Company will consider various financing alternatives, including retention of funds from operations, debt financing and issuance of additional Common Shares and other securities. The Company will evaluate the appropriate financing alternatives closely and make use of such options dependent on the given investment situation and the capital markets. If cash flows are other than projected, capital expenditure levels may be adjusted. In addition, depending on a number of factors including commodity prices, industry conditions and the Company's financial and operating results, funds from credit facilities and equity financings may not be available on terms acceptable to the Company, which could also result in adjustments to the capital program as required. There can be no guarantee that funds will be available or that the Company will be able to allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of the Company's assets uneconomic. See "*Significant Factors or Uncertainties Affecting Reserves Data*".

FUTURE DEVELOPMENT COSTS
EGYPT
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

(US$MM)	Forecast Prices and Costs	
Year	Proved Reserves	Proved Plus Probable Reserves
2019	6.1	13.5
2020	5.0	7.6
2021	—	—
2022	—	—
2023	—	—
Remaining	—	—
Total Undiscounted	11.1	21.0
Discounted at 10%	10.1	19.4

FUTURE DEVELOPMENT COSTS
CANADA
AS OF DECEMBER 31, 2018
(FORECAST PRICES AND COSTS)

(US$MM)	Forecast Prices and Costs	
Year	Proved Reserves	Proved Plus Probable Reserves
2019	13.7	15.6
2020	11.7	13.6
2021	10.2	12.1
2022	8.2	23.3
2023	—	11.3
Remaining	—	14.4
Total Undiscounted	43.7	90.3
Discounted at 10%	37.1	68.8

Other Oil and Gas Information

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2018. All of the Company's wells are located onshore.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Egypt	115.0	114.7	122.0	121.6	—	—	—	—
Canada	55.0	53.0	16.0	10.7	63.0	61.0	18.0	8.0
Total	170.0	167.7	138.0	132.3	63.0	61.0	18.0	8.0

Properties with No Attributed Reserves

The following table sets out the Company's developed and undeveloped land holdings as at December 31, 2018.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Egypt	14,346	14,346	1,021,827	1,021,827	1,036,172	1,036,172
Canada	10,050	8,629	36,972	33,837	47,022	42,466
Total	24,396	22,975	1,058,799	1,055,664	1,083,194	1,078,638

Commitments

Pursuant to the PSC for North West Sitra in Egypt, the Company had a minimum financial commitment of $10.0 million and a work commitment for two wells and 300 square kilometers of 3-D seismic during the initial three-and-a-half year exploration period, which commenced on January 8, 2015. The Company requested and received a six month extension of the initial exploration period to January 7, 2019. As at December 31, 2018, the Company has met its financial and operating commitments, with the acquisition of 600 square kilometers of 3-D seismic in 2017 and the drilling of two wells in 2018. The Company has completed the initial exploration period work program and based on well results is not planning to enter the second exploration phase. On January 7, 2019, the Company relinquished its interest in the NW Sitra concession.

Development of properties with no attributable reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" and "*Industry Conditions*" herein. In addition, the Company expects that funding of development operations on such properties will be evaluated in the context of the Company's total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Development of the Company's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein. In addition, we expect that funding of development operations on such properties will be evaluated in the context of our total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Forward Contracts

In conjunction with the prepayment agreement executed in 2017, TPI has also entered into a marketing contract with Mercuria to market 9 million barrels of TPI's Egypt entitlement production. The pricing of the crude oil sales will be based on market prices at the time of sale. In conjunction with the prepayment and marketing agreements, the Company is committed to hedge 60% of its forecasted proved entitlement production.

Subject to the Company's Hedging Policy, TransGlobe uses hedging arrangements from time to time as part of its risk management strategy to manage commodity price fluctuations and stabilize cash flows for future exploration and development programs. The hedging program is actively monitored and adjusted as deemed necessary to protect the cash flows from the risk of commodity price exposure.

The nature of TransGlobe's operations exposes it to fluctuations in commodity prices, interest rates and foreign currency exchange rates. TransGlobe monitors and, when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by TransGlobe are related to an underlying financial position or to future crude oil and natural gas production. TransGlobe does not use derivative financial instruments for speculative purposes. TransGlobe has elected not to designate any of its derivative financial instruments as accounting hedges and thus accounts for changes in fair value in net earnings at each reporting period. TransGlobe has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts. The derivative financial instruments are initiated within the guidelines of the Company's Hedging Policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

Refer to the annual Consolidated Financial Statements for our commitments under all hedging agreements as at December 31, 2018.

Additional Information Concerning Abandonment and Reclamation Costs

In Egypt, estimated future abandonment and reclamations costs related to properties evaluated have not been taken into account by GLJ. Under the terms of the PSCs, ownership in the facilities and wells is transferred to the Government of Egypt through cost recovery. Therefore the future abandonment and reclamation costs have been assessed a zero value.

In connection with the Company's Canadian operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The expected total reserve well abandonment and reclamation costs, net of estimated salvage value, included in the GLJ Report for the 209.7 net wells under the proved reserves category is $10.7 million undiscounted, of which a total of $0.6 million is estimated to be incurred through 2019.

Tax Horizon

In 2018, the Company did not pay any income taxes in Canada and does not anticipate any taxes payable in the near future. In Egypt, the Company's income tax liabilities are paid out of the government's share of production. As such, all current income tax liabilities in Egypt are settled immediately as they become due.

Capital Expenditures

The following table summarizes the capital expenditures (including capitalized general and administrative expenses) related to the Company's activities for the year ended December 31, 2018:

	Egypt	Canada	Total
(US$M)			
Exploration costs	8,757	530	9,287
Development costs	19,398	11,435	30,833
Corporate and other	518	68	586
Total	28,673	12,033	40,706

Exploration and Development Activities

The following tables set forth the gross and net exploratory and development wells which the Company drilled in Egypt during the year ended December 31, 2018:

Egypt	Gross			Net		
	Exploration	Development	Total	Exploration	Development	Total
Crude Oil	1.0	8.0	9.0	1.0	8.0	9.0
Dry and Abandoned	3.0	—	3.0	3.0	—	3.0
Total	**4.0**	**8.0**	**12.0**	**4.0**	**8.0**	**12.0**

Canada	Gross			Net		
	Exploration	Development	Total	Exploration	Development	Total
Crude Oil	—	6.0	6.0	—	5.0	5.0
Total	**—**	**6.0**	**6.0**	**—**	**5.0**	**5.0**

Current development activities are focused on the West Gharib, West Bakr and NW Gharib concessions in Egypt, and the Harmattan area in Canada. Other key areas for 2019 include the exploration drilling at West Bakr, NW Gharib and South Ghazalat in Egypt.

Production Estimates

The following table sets out the volume of the Company's daily production (working interest before royalties) estimated for the year ending December 31, 2019 by GLJ which is reflected in the estimate of future net revenue (Forecast Price Case) disclosed in the prior reserves summary tables.

	Egypt					Canada			Total
	South Ghazalat	West Gharib	West Gharib	West Bakr	NW Gharib				Company
	Light Crude Oil	Medium Crude Oil	Heavy Crude Oil	Heavy Crude Oil	Heavy Crude Oil	Light Crude Oil	Natural Gas	NGLs	
	Gross (bbls/d)	Gross (bbls/d)	Gross (bbls/d)	Gross (bbls/d)	Gross (bbls/d)	Gross (bbls/d)	Gross (Mcf/d)	Gross (bbls/d)	Gross (boe/d)
Proved Developed Producing	—	903	3,185	5,493	831	472	5,227	821	12,576
Non-Producing	—	167	167	765	19	503	505	86	1,791
Proved Undeveloped	118	139	46	558	—	299	253	43	1,246
Total Proved	118	1,209	3,398	6,816	850	1,274	5,985	951	15,613
Total Probable	386	179	268	1,255	189	105	142	22	2,427
Total Proved Plus Probable	504	1,388	3,666	8,071	1,039	1,379	6,128	972	18,040

Production History

The following table summarizes certain information in respect of sales volumes, product prices received, royalties paid, operating expenses and resulting netbacks made by the Company (and its subsidiaries) for the periods indicated:

	2018			
	Quarter Ended			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
Average Daily Production Volumes				
Egypt[1]				
Heavy Crude Oil (bbls/d)	10,797	10,927	11,056	12,009
Light Crude Oil and Medium Crude Oil (bbls/d)	980	985	883	959
Canada[2]				
Light Crude Oil and Medium Crude Oil (bbls/d)	675	497	567	495
Conventional Natural Gas (boe/d)	1,029	849	949	978
Natural Gas Liquids (bbls/d)	894	521	876	829
Combined (boe/d)[3]	*14,375*	*13,779*	*14,331*	*15,270*
Average Daily Sales Volumes				
Egypt				
Heavy Crude Oil (bbls/d)	8,393	15,993	11,203	11,281
Light Crude Oil and Medium Crude Oil (bbls/d)	762	1,441	895	900
Canada				
Light Crude Oil and Medium Crude Oil (bbls/d)	675	497	567	495
Conventional Natural Gas (boe/d)	1,029	849	949	978
Natural Gas Liquids (bbls/d)	894	521	876	829
Combined (boe/d)[3]	*11,753*	*19,301*	*14,490*	*14,483*
Average Price Received				
Egypt[1]				
Heavy Crude Oil (US$/bbl)	56.20	59.34	61.87	61.39
Light Crude Oil and Medium Crude Oil (US$/bbl)	56.20	59.34	61.87	61.39
Canada				
Light Crude Oil and Medium Crude Oil (US$/bbl)	57.15	60.87	60.02	28.79
Conventional Natural Gas (US$/boe)	1.70	1.08	1.01	1.22
Natural Gas Liquids (US$/bbl)	27.72	38.39	22.64	24.39
Combined (US$/boe)	*50.06*	*56.49*	*55.77*	*54.51*
Royalties and Taxes				
Egypt[1]				
Heavy Crude Oil (US$/bbl)	40.04	23.43	34.32	34.14
Light Crude Oil and Medium Crude Oil (US$/bbl)	40.04	23.43	34.32	34.14

Canada				
Light Crude Oil and Medium Crude Oil (US$/bbl)	5.41	2.30	2.79	1.78
Conventional Natural Gas (US$/boe)	5.41	2.30	2.79	1.78
Natural Gas Liquids (US$/bbl)	5.41	2.30	2.79	1.78
Combined (US$/bbl)	*32.38*	*21.38*	*29.11*	*28.99*
Operating Expenses				
Egypt[1]				
Heavy Crude Oil (US$/bbl)	10.27	9.58	9.59	10.01
Light Crude Oil and Medium Crude Oil (US$/bbl)	10.27	9.58	9.59	10.01
Canada[4,5,6]				
Light Crude Oil and Medium Crude Oil (US$/bbl)	9.32	12.31	7.11	8.96
Conventional Natural Gas (US$/boe)	9.32	12.31	7.11	8.96
Natural Gas Liquids (US$/bbl)	9.32	12.31	7.11	8.96
Combined (US$/bbl)	*10.06*	*9.85*	*9.18*	*9.84*
Selling Costs				
Egypt[1]				
Heavy Crude Oil (US$/bbl)	0.06	0.68	0.47	0.40
Light Crude Oil and Medium Crude Oil (US$/bbl)	0.06	0.68	0.47	0.40
Canada				
Light Crude Oil and Medium Crude Oil (US$/bbl)	—	—	—	—
Conventional Natural Gas (US$/boe)	—	—	—	—
Natural Gas Liquids (US$/bbl)	—	—	—	—
Combined (US$/bbl)	*0.04*	*0.61*	*0.40*	*0.34*
Netback Received [7]				
Egypt[1]				
Heavy Crude Oil (US$/bbl)	5.83	25.65	14.49	16.84
Light Crude Oil and Medium Crude Oil (US$/bbl)	5.83	25.65	14.49	16.84
Canada[8,9]				
Light Crude Oil and Medium Crude Oil (US$/bbl)	42.42	46.26	50.12	18.05
Conventional Natural Gas (US$/boe)	(13.03)	(13.53)	(8.89)	(9.52)
Natural Gas Liquids (US$/bbl)	12.99	23.78	12.74	13.65
Combined (US$/bbl)	*7.58*	*24.65*	*17.08*	*15.34*

[1] All production from West Gharib, West Bakr and NW Gharib is sold as a blended crude oil. Royalties and taxes are calculated on a concession basis without distinction between Heavy Crude Oil and, Medium and Light Crude Oil.

[2] Includes minor royalty volumes received but does not deduct royalty volumes paid.

[3] The Company directly markets its share of entitlement oil from the West Gharib and West Bakr concessions. Reported sales volumes fluctuate quarter to quarter depending on the timing of liftings. Under-lifted entitlement oil is held and booked as inventory. At year-end 2018, the Company held 568.1 mbbls of entitlement inventory.

[4] Includes solution gas and by-products.

[5] Operating costs have been allocated to each product type based on proportionate revenue splits and other reasonable methods of allocation.

[6] Operating costs include all costs related to the operation of wells, facilities and gathering systems, transportation and NGLs processing.

[7] Netbacks are calculated by subtracting royalties, operating and transportation costs from revenues. Netbacks do not include other income.

[8] Includes NGLs.

[9] Average prices received, royalties, operating costs and netbacks have not been provided separately for NGLs as they have been included with the amounts stated above for conventional natural gas, as conventional natural gas is the primary revenue stream.

The following table indicates the Company's average daily volumes from its important fields for the year ended December 31, 2018:

	Heavy Crude Oil	Light and Medium Crude	Natural Gas	Natural Gas Liquids	Total
	(bbls/d)	(bbls/d)	(mcf/d)	(bbls/d)	(boe/d)
Egypt					
West Gharib	3,868	951	—	—	4,819
West Bakr	6,168	—	—	—	6,168
NW Gharib	1,163	—	—	—	1,163
Canada	—	558	5,707	780	2,289
Total	11,199	1,509	5,707	780	14,439

DIVIDEND POLICY

TransGlobe's dividend policy is to return capital to shareholders through semi-annual payments of a significant portion of free cash flow. For these purposes, free cash flow is defined as net cash generated by operating activities less capital expenditures, debt repayments, and anticipated business development capital, calculated on an annual basis.

The declaration and payment of future dividends is subject to the sole discretion of the Board of Directors of the Company and may vary dependent upon a number of factors, including: commodity price volatility, production levels, compliance with any restrictions on the payment of dividends contained

in any agreements and/or legislation that the Company is subject to, foreign exchange movements, operating costs, capital expenditures, anticipated business development capital requirements, royalties, and taxes. Dependent upon the foregoing and other factors deemed relevant by the Board and Management of the Company to the declaration and payment of dividends, the Company may change its dividend policy at any time. Although the Company intends to continue its dividend program, dividends are not guaranteed. Any reduction of dividends may have an adverse effect on the market price of the Company's common shares.

No dividends were paid on the Company's Common Shares in 2016 or 2017. The Company has paid the following dividend on its Common Shares during the year ended December 31, 2018.

Ex-dividend date	Record date	Payment date	Per share amount
August 30, 2018	August 31, 2018	September 14, 2018	$0.035

The Company declared the following dividend subsequent to year end.

Ex-dividend date	Record date	Payment date	Per share amount
March 28, 2019	March 29, 2019	April 18, 2019	$0.035

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

TransGlobe is authorized to issue an unlimited number of Common Shares without nominal or par value. As at March 13, 2019 there were 72,492,071 Common Shares issued and outstanding.

Each Common Share entitles its holder to: (i) vote at any meeting of Shareholders of the Company; (ii) to receive any dividend declared by the Company; and (iii) to receive the remaining property of the Company upon dissolution.

The Company's articles have been filed in accordance with NI 51-102 and are available on the Company's SEDAR profile at www.sedar.com and the Company's EDGAR profile at www.sec.gov.

MARKET FOR SECURITIES

TransGlobe's Common Shares trade on the TSX and the AIM market of the London Stock Exchange under the symbol TGL and on the Nasdaq under the symbol TGA.

Common Shares

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the TSX for the indicated periods:

(Canadian dollars, except volumes)	Price Range		
	High ($/share)	Low ($/share)	Volume
2018			
January	1.86	1.72	1,318,441
February	1.81	1.60	742,485
March	1.87	1.60	554,911
April	2.31	1.60	1,725,252
May	3.30	2.36	3,981,300
June	3.64	2.96	2,097,835
July	5.32	3.76	4,935,083
August	4.58	3.87	2,841,599
September	4.92	4.22	1,711,074
October	4.48	2.71	3,852,278
November	3.23	2.68	2,402,550
December	2.93	2.07	1,518,131
2019			
January	2.75	2.29	1,062,613
February	2.81	2.44	663,301
March (1 to 8)	2.77	2.64	254,377

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the Nasdaq for the indicated periods:

(U.S. dollars, except volumes)	Price Range		
	High ($/share)	**Low ($/share)**	**Volume**
2018			
January	1.49	1.39	1,991,769
February	1.46	1.27	1,409,111
March	1.45	1.25	975,700
April	1.80	1.26	2,466,948
May	2.64	1.83	10,774,321
June	2.77	2.24	8,308,307
July	4.05	2.73	18,626,752
August	3.49	2.93	11,346,162
September	3.74	3.21	7,787,266
October	3.52	2.03	14,091,068
November	2.47	2.01	4,565,304
December	2.18	1.52	3,632,562
2019			
January	2.09	1.73	2,256,842
February	2.12	1.84	1,410,169
March (1 to 8)	2.06	1.98	475,301

The following table sets out the monthly high and low closing prices and the total monthly trading volumes for the Common Shares on the AIM for the indicated periods:

(Pound sterling, except volumes)	Price Range		
	High (£/share)	**Low (£/share)**	**Volume**
2018			
June 29	2.06	2.06	4,960
July	2.76	2.06	47,846
August	2.64	2.28	7,721
September	2.74	2.57	3,318
October	2.63	1.90	364
November	1.90	1.78	2,738
December	1.78	1.48	2,314
2019			
January	1.58	1.43	680
February	1.60	1.43	98
March (1 to 8)	1.60	1.60	—

PRIOR SALES

The following table summarizes the issuance of stock options, which are convertible into Common Shares, during the year ended December 31, 2018:

Date of Issuance	Number of Stock Options	Price per Stock Option
May 18, 2018	1,070,829	C$2.62

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

As at the date hereof, none of the Company's securities are subject to escrow or contractual restrictions on transfer.

DIRECTORS AND OFFICERS

The name and place of residence of each director and officer, the offices held by each in the Company, the principal occupation of each director and officer, the period served as director or officer and the aggregate number of securities of the Company owned by such individuals as at March 13, 2019 is set as below:

Name and Place of Residence	Position Held	Year Became Director or Officer	Principal Occupation and Positions for the Past Five Years
Robert G. Jennings [1] Alberta, Canada	Chairman of the Board and Director	2011	Retired as Chairman and CEO of Jennings Capital Inc. in May, 2011. Prior to founding Jennings Capital in 1993, Senior Vice President and Director with Midland Walwyn Capital Inc, co-founder of Carson Jennings & Associates, Director and Vice President with McLeod Young Weir.
Randy C. Neely [4] London, England	President, Chief Executive Officer and Director	2012	President of the Company since January 10, 2018 and previously Vice President Finance and CFO since May 8, 2012. Elected to the Board in May 2018 and was appointed as President and CEO of the Company in January 2019. Prior to joining TransGlobe was Chief Financial Officer at Zodiac Exploration Inc. and Chief Financial Officer at BlackPearl Resources Inc. Industry professional with over 25 years' experience.
Carol Bell [1][3] London, England	Director	2019	Former Managing Director of Chase Manhattan Bank's Global Oil & Gas Group, Head of European Equity Research at JP Morgan and several years as an equity research analyst in the oil and gas sector at Credit Suisse First Boston and UBS Phillips & Drew. Over 35 years of experience in the natural resource sector. Currently sits on the Board at BlackRock Commodities, Bonheur ASA, Ophir Energy plc and Tharisa plc and has served or serves on several private and charitable boards.
Matthew Brister [2][3] Alberta, Canada	Director	2017	Previously President and CEO of Chinook Energy and most recently Chairman of the Company. Previously served as CEO Storm Ventures International (SVI), President and CEO of Storm Energy Ltd and Storm Energy Inc. Held various positions with Pinnacle Resources including President and CEO. Over 40 years experience in the domestic and international energy sector.
Ross G. Clarkson [2][4] British Columbia, Canada	Director	1995	Appointed to the Board of Directors in October of 1995 and served as President and CEO until January 2018 with more than 40 years of oil and gas exploration, management and executive experience. In January 2018, was appointed as CEO until January 2019.
David B. Cook [1][3] Copenhagen, Denmark	Director	2014	Former Head of Strategy for INEOS Oil & Gas. Prior thereto, Mr. Cook was CEO INEOS DeNoS, located in London, UK having taken that role following the sale to INEOS, DONG Oil and Gas (part of the DONG Energy group, now Orsted) where he was also CEO. Prior to that he was Executive Officer and Head of Oil and Gas at the Abu Dhabi National Energy Company ("TAQA") where he led the Company's upstream and midstream interests in the Middle East, North America, the United Kingdom and Europe. Before joining TAQA, he served as Vice President for BP Russia, responsible for BP's non-TNK-BP exploration and production activities in Russia. Mr. Cook has held a variety of global technical, commercial and managerial positions based from the US, UK, Russia and the Middle East as well as board of director roles.
Edward LaFehr [1][2] Alberta, Canada	Director	2019	Chief Executive Officer of Baytex Energy Corporation effective May 2017 and President from July 2016 to April 2017. Previously he served as COO of TAQA's global operations and was located in Abu Dhabi from April 2014 - June 2016 and President of TAQA's North America division located in Calgary from October 2012 - April 2014. Mr. LeFehr has 35 years of experience in the oil and gas industry working with Amoco, BP, Talisman and Abu Dhabi National Energy Company ("TAQA"), holding senior positions in North American, Europe and the Middle East regions.
Susan M. MacKenzie [2][3] Alberta, Canada	Director	2014	Served as Chief Operating Officer with Oilsands Quest Inc., a NYSE Amex-listed oil sands company, from April - September, 2010. Prior thereto, Ms. MacKenzie was employed for 12 years at PetroCanada, where she held senior roles including Vice President, Human Resources and Vice President of In-Situ Development and Operations. Ms MacKenzie was with Amoco Canada Petroleum Company Ltd. for 14 years in a variety of engineering and leadership roles in natural gas, conventional and heavy oil exploitation.
Steven Sinclair [1][3] Alberta, Canada	Director	2017	Previously served as Senior Vice President and Chief Financial Officer of ARC Resources Ltd until his retirement in 2014. Mr. Sinclair has over 30 years' financial and operating experience and senior management experience.
Lloyd W. Herrick [4] London, England	Vice-President and Chief Operating Office	1999	Vice-President and Chief Operating Officer of the Company since April 28, 1999, with over 40 years experience in both domestic and international oil and gas exploration and development.
Edward D. Ok [4] London, England	Vice-President, Finance and Chief Financial Officer	2018	Vice President, Finance and Chief Financial Officer of the Company since January 2018 and with the Company since 2012 in senior financial roles. Prior to joining TransGlobe was at Zodiac Exploration. Mr. Ok is a Chartered Accountant with over 10 years industry experience.
Marilyn Vrooman-Robertson Alberta, Canada	Corporate Secretary	2017	Corporate Secretary since 2017 and previously served as Assistant Corporate Secretary. Governance professional with over 18 years' experience. A student of the International Chartered Secretary Association and a member of Governance Professionals of Canada.

[1] Member of the Company's Audit Committee. Mr. Jennings and Mr. Cook were members of the Audit Committee until May 10, 2018.

[2] Member of the Company's Reserves, Health, Safety, Environment & Social Responsibility Committee.

[3] Member of the Compensation, Human Resources and Governance Committee.

[4] Member of the Disclosure & Compliance Committee. Mr. Clarkson was a member of the Disclosure & Compliance Committee for the period from June 29, 2018 to December 31, 2018.

[5] As at March 12, 2019, the directors and officers of TransGlobe, as a group, beneficially owned or controlled or directed, directly or indirectly, 3,004,992 Common Shares or approximately 4.1% of the issued and outstanding Common Shares.

Cease Trade Orders

Except as otherwise disclosed herein, no current director or executive officer of the Company has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that:

(i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade order or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or

(ii) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade order or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Bankruptcies

Except as otherwise disclosed herein, no current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Dr. Bell was formerly the non-executive chairman of Barcud Derwen Ltd. ("**Barcud Derwen**"), a private television facilities house based in Wales and Scotland. Barcud Derwen was put into administration by its board of directors in June 2010 whereby the majority of its assets were sold. Following the sale of Barcud Derwen's assets, Dr. Bells ceased involvement with Barcud Derwen.

In addition, no current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or securityholder.

Penalties or Sanctions

No current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Directors and officers of the Company may, from time to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA, which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Risk Factors*".

INTERESTS OF EXPERTS

Names of Experts

Other than as described below, there is no person or corporation who is named as having prepared or certified a statement, report or valuation described and included in the filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to the Company's most recently completed financial year whose profession or business gives authority to the report, valuation, statement or opinion made by the person, or Company, other than GLJ, the Company's independent engineering evaluator, and Deloitte LLP, the Company's independent auditor.

Interests of Experts

There were no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of its associates or affiliates: (i) held by GLJ or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of GLJ, when GLJ prepared the report, valuation, statement or opinion referred to herein as having been prepared by GLJ; (ii) received by GLJ or by the "designated professionals" of GLJ, after the time specified above; or (iii) to be received by GLJ or by the "designated professionals" of GLJ; except in each case for the ownership of Common Shares, which in respect of GLJ and GLJ's "designated professionals", as a group, has at all relevant times represented less than 1% of the outstanding Common Shares. In addition, neither GLJ, nor any director, officer or employee of GLJ, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

Deloitte LLP is independent of the Company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules and standards of the Public Company Accounting Oversight Board and the securities laws and regulations administered by the U.S. Securities and Exchange Commission.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings material to the Company to which the Company is or was a party to, or in respect of which any of its properties are or were the subject of, during the 2018 financial year, nor are there any such proceedings known to be contemplated. In addition, there were no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the 2018 financial year, no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and no settlement agreements entered into by the Company before a court relating to securities legislation or with a securities regulatory authority during the 2018 financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% of the Company's Common Shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would reasonably be expected to materially affect the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

MATERIAL CONTRACTS

Other than discussed herein, there are no material contracts, other than the contracts entered into in the ordinary course of business, that are material to the Company and that were entered into within the most recently completed financial year, or before the most recently completed financial year but are still in effect other than the C$30 million reserves-based lending facility agreement dated May 16, 2017, as amended May 11, 2018, described under "*General Development of the Business - 2017*", which is available on the Company's profile on SEDAR at www.sedar.com

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The audit committee of the Company (the "**Audit Committee**") is currently comprised of Steven Sinclair (Chair), Dr. Carol Bell and Edward LaFehr. The following chart sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Steven Sinclair Alberta, Canada	Yes	Yes	Mr. Sinclair is a corporate director. Mr. Sinclair previously served as Senior Vice President and Chief Financial Officer of ARC Resources Ltd until his retirement in 2014 and is currently a director and chair of the audit committee of a Calgary headquartered private oil and gas Company. Mr. Sinclair has over 30 years of financial and operating experience. Mr. Sinclair received his Bachelor of Commerce degree from the University of Calgary in 1978 and his Chartered Accountant's designation in 1981.
Carol Bell London, England	Yes	Yes	Dr. Bell is an independent businesswoman and corporate director with over 35 years experience in the natural resources sector. Dr. Bell was Managing Director, Global Oil & Gas Group of Chase Manhattan Bank from 1997 - 1999. Prior thereto, Dr. Bell was Managing Director, Equity Research at JP Morgan from 1991 - 1997, Vice President, Equity Research Credit Suisse First Boston from 1990 - 1991, European Oil Analyst with UBS Phillips & Drew from 1986 - 1990, Commercial Executive with Charterhouse Petroleum plc 1983 - 1986 and Commercial Analyst with RTZ Oil & Gas Limited 1980 - 1983. Dr. Bell has a MA, Natural Sciences, BA Earth Sciences and a PhD Archeology.
Edward LeFehr Alberta, Canada	Yes	Yes	Mr. LaFehr is President and CEO of Baytex Energy Corporation. Mr. LaFehr has over 35 years experience in the oil and gas industry working with Amoco, BP, Talisman and Abu Dhabi National Energy Company ("TAQA"), holding senior positions in Norther American, Europe and the Middle East regions. Prior to joining Baytex, Mr LaFehr President of TAQA's North American oil and gas business based in Calgary and subsequently COO for TAQA, globally. Mr. LaFehr holds Masters degrees in geophysics and mineral economics from Stanford University and the Colorado School of Mines respectively.

Pre-Approval of Policies and Procedures

It is within the mandate of the Company's Audit Committee to approve all audit and non-audit related fees. The Audit Committee is informed routinely as to the non-audit services to be provided by the auditor pursuant to this pre-approval process. The auditors also present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

The Audit Committee's pre-approval procedure is to approve all non-audit services to be performed by the Company's auditors in advance of the engagement of the Company's auditors to perform such services. The pre-approval process involves management presenting the Audit Committee with a description of any proposed non-audit services. The Audit Committee considers the appropriateness of such services and whether the provision of

those services would impact the auditor's independence, including the magnitude of the potential fees. Once the committee has satisfied itself of its concerns, if any, it then votes either in favor of or against contracting the Company's auditors to perform the proposed non-audit services.

Audit Committee Charter

The full text of the Company's audit committee charter is included in Schedule "C" to this AIF.

Principal Accountant Fees and Services

The aggregate fees for professional services billed to TransGlobe by Deloitte LLP during the fiscal years ended December 31, 2018 and December 31, 2017 were as follows:

(Canadian dollars)	Fiscal Year Ended December 31, 2018	Fiscal Year Ended December 31, 2017
Audit Fees	$ 461,749	$ 499,957
Audit Related Fees	24,075	137,767
Tax Fees	28,483	115,268
TOTAL	$ 514,307	$ 752,992

The nature of the services provided by Deloitte LLP under each of the categories indicated in the table is described below.

Audit Fees

Audit fees were for professional services rendered by Deloitte LLP for the audit of the Company's annual financial statements, as well as for the review of the Company's interim quarterly financial statements.

Audit Related Fees

Audit related fees were for professional services rendered by Deloitte LLP for assurance services that are reasonably related to the performance of the audit of the Company's annual financial statements (not included in audit fees).

Tax Fees

Tax fees were for tax compliance, including the review of tax returns, tax advice and tax planning and advisory services relating to common forms of domestic and international taxation (i.e. income tax, capital tax, goods and services tax and payroll tax).

All Other Fees

During the fiscal years ended December 31, 2018 and 2017, no other fees were incurred other than those described above.

CANADIAN INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Company is unable to predict what additional legislation or amendments governments may enact in the future.

The Company holds interests in crude oil and natural gas properties, along with related assets, in the Canadian province of Alberta. The Company's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Company's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinate of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the National Energy Board Act (Canada) (the "NEB Act") and the National Energy Board Act Part VI (Oil and Gas) Regulation (the "Part VI Regulation"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "NEB") is required. There is no longer a public hearing requirement for the export of natural gas and NGLs. Instead, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("Cabinet").

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the federal government.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("CER"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

The Company does not directly enter into contracts to export its Canadian production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition creates further uncertainty. In addition, export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin, has an expected in-service date in the latter half of 2019.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Court's direction, the Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision including the environmental effects of related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. While Cabinet has three months to consider the NEB's report, it may extend this deadline to accommodate a new round of indigenous consultation, upon completion of which it will approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast, see "Canadian Industry Conditions - Regulatory Authorities and Environmental Regulation - Federal".

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first railcars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to $4 per barrel; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. Little is known about this strategy, but the deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

To increase market access and reduce the associated price differential experienced in Western Canada, the Alberta provincial government began negotiations in late November 2018 to purchase up to 120,000 bopd of rail capacity for three years (starting late 2019). Moreover, on December 2, 2018, the Alberta provincial government announced the implementation of crude oil and bitumen production cuts of 8.7% to reduce 325,000 bopd of production in early January 2019 (reduced to 95,000 bopd by December 31, 2019). The reduction applies to oil sands and conventional oil producers in excess of 10,000 bopd.

On May 29, 2018, the federal government reached an agreement with Kinder Morgan to purchase the company's Trans Mountain Expansion Project and related pipeline and terminal assets for C$4.5 billion. The Project involves building a new pipeline along the existing area running 1,150 km from Edmonton, Alberta to Burnaby, British Columbia, to improve market access to the U.S. Pacific Coast and Northeast Asia and increase daily capacity from 300,000 to 890,000 barrels. On August 30, 2018, the Federal Court of the Appeal ruled against the Trans Mountain Pipeline, canceling the NEB decision to approve the pipeline. In response, the federal government filed reply evidence with the NEB on December 11, 2018 to address the findings of the Federal Court of Appeal and is currently under review.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules (Alberta), the Government of Alberta will, on a monthly basis, direct crude oil producers producing more than 10,000 bbls/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d - a reduction of approximately 8.7% of total daily average crude oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 bbls/d to a maximum output of approximately 3.63 million bbls/d.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States

and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

On November 30, 2018, U.S. President Donald Trump, Prime Minister Trudeau, and outgoing Mexican President Enrique Peña Nieto signed an authorization for a new trade deal that will replace NAFTA. The "New NAFTA" is referred to as the United States-Mexico-Canada Agreement ("USMCA"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when the end of the NAFTA era will be. As the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Company's business.

As discussed above, at the end of 2018 the Government of Alberta announced curtailment of Alberta's crude oil and bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA; as a result, the amount of crude oil and bitumen (sold at an extreme differential) that Canada is required to offer may be reduced. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

Therefore, reducing the Canadian supply reduced the required offering, and the amount of oil and bitumen Canada sells at undervalue. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("CPTPP"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement - Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences. In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Western Canada. In each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("IOGC"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

In addition, the federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make C$1.6 billion available to the crude oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "Modernized Framework") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "Old Framework") will continue to apply to wells drilled prior to December 31, 2016 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator (the "AER") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sand production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for Western Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("GHG") emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "Agency") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the Cabinet; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related Acts including the *Oil and Gas Conservation Act* (the "OGCA")*, the Oil Sands Conservation Act, the Pipeline Act,* and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat. The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

Alberta

The AER administers the licensee Liability Management Rating Program (the "AB LMR Program"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "AB LLR Program"), the Oilfield Waste Liability Program (the "AB OWL Program") and the Large Facility Liability Management Program (the "AB LFP"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee who's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("LMR"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "Orphan Fund") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant ("WIP") becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In Redwater Energy Corporation (Re) ("Redwater"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal Bankruptcy and Insolvency Act (the "BIA"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings, and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company’s valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licencee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

The AER has also implemented the Inactive Well Compliance Program (the "IWCP") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER

has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP completed its third year on March 31, 2018 but the AER has not yet released its third annual report.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2019, 185 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "Framework"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario, and New Brunswick in April 2019; it will take effect in the Yukon, and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "Federal Methane Regulations"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "CLP"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Government of Alberta has announced it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "CCIR"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes*

Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "ESTMA") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to Shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. These activities involve a number of risks and uncertainties inherent in the industry, some of which are summarized below. If any of the risks described below materializes, the Company's business, financial condition, operating results or prospects could be materially and adversely affected. The following are material risks identified by the Company; however, risks that are at this time unknown to management of the Company or that the Company currently deems immaterial may develop and may have a material adverse effect upon its business, financial condition, operating results and prospects.

Risks Relating to Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different evaluators, or by the same evaluators at different times may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, GLJ has used forecast prices and costs in estimating the reserves and future net cash flows. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and natural gas reserves will vary from the estimates contained in the reserve evaluations, and such variations could be material. The reserve evaluations are based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluations.

Prices and Markets

Prices for oil and natural gas are subject to large fluctuations in response to changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with greenhouse gas ("GHG") emissions legislation at the Canadian provincial or federal levels. Climate change policy in Canada is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 % from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate

of C$30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or asset write-offs.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms. See "Risk Factors – Non-Governmental Organizations and Eco and Eco-Terrorism Risks" and *"Risk Factors – Reputational Risk"*.

All these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Share Price Volatility and Liquidity

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. In certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Company could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Company will trade cannot be accurately predicted.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Common Shares are quoted and the price which investors may realize for their Common Shares may be influenced by a large number of factors, some of which are general or market specific, others which are sector specific and others which are specific to the Company and its operations. These factors include, without limitation; (i) the performance of the Company and the overall stock market; (ii) large purchases or sales of Common Shares by other investors; (iii) results of exploration, development and appraisal programmes and production operations; (iv) changes in analysts' recommendations and any failure by the Company to meet the expectations of the research analysts; (v) changes in legislation or regulations and changes in general economic, political or regulatory conditions; and (vi) other factors which are outside of the control of the Company. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. Accordingly, the price at which the Common Shares of the Company will trade cannot be accurately predicted.

In order to finance future operations or acquisition opportunities, the Company may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Company cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Company's securities will have on the market price of the Common Shares.

Shareholders may sell their Common Shares in the future to realize their investment. Sales of substantial amounts of Common Shares, or the perception that such sales could occur, could materially adversely affect the market price of the Common Shares available for sale compared to the demand to buy Common Shares. Such sales may also make it more difficult for the Company to sell equity securities in the future at a time and price that is deemed appropriate. There can be no guarantee that the price of the Common Shares will reflect their actual or potential market value or the underlying value of the Company's net assets.

A number of factors, including concerns about the effects of the use of fossil fuels on climate change, concerns about the impact of oil and gas operations on the environment, concerns about environmental damage relating to spills of petroleum products during transportation and concerns about indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board and management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

The Company is principally aiming to achieve capital growth and, therefore, Common Shares may not be suitable as a short-term investment. Consequently, the share price may be subject to greater fluctuation on small volumes of shares traded, and thus the Common Shares may be difficult to sell at a particular price. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market

price of the Common Shares may not reflect the underlying value of the Company. There can be no guarantee that the value of an investment in the Company will increase. Investors may therefore realize less than, or lose all of, their original investment.

Management of Growth

The Company considers acquisitions of businesses and assets in the ordinary course of business, including acquisitions in new geographical areas. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters.

As a result, the Company may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Competition

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Company and a lower cost of capital. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Operating Risks

The Company delivers crude oil through gathering, processing pipeline systems and export cargo terminals that the Company does not own or control. The amount of crude oil that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing pipeline systems and scheduling of export cargos (in Egypt). The lack of availability of capacity in any of the gathering, processing pipeline systems and export cargo terminals, and in particular the export cargo terminals in Egypt, could result in the Company's inability to realize the full economic potential of its production, sales or in a reduction of the price offered for the Company's production.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. If any of these types of events were to occur, they could result in failure to discover hydrocarbons and if discovered delay in or loss of production, environmental damage, injury to persons or loss of life. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to equipment owned or used by the Company and personal injury, wrongful death or other claims related to loss being brought against the Company. These events could result in the Company being required to take corrective measures, incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Company and/or its officers. The Company may also be required to curtail or cease operations on the occurrence of such events. Any of the above could have a material adverse effect on the Company’s business, prospects, financial condition or results of operations.

Whilst the Company intends to implement certain policies and procedures to identify and mitigate such hazards, develop appropriate work plans and approvals for high-risk activities and prevent accidents from occurring, these procedures may not be sufficiently robust or appropriately followed by the Company’s staff or third-party contractors to prevent accidents. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas drilling and production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The oil and gas industry in Egypt is not as efficient or developed as the oil and gas industry in North America. As a result, the Company's exploration and development activities may take longer to complete and may be more expensive than similar operations in North America. The availability of technical expertise, specific equipment and supplies may be more limited than in North America. The Company expects that such factors will subject its operations to economic and operating risks that may not be experienced in North American operations.

Egypt Government Credit Risk

The Company is and may in the future be exposed to third party credit risk through its contractual arrangements with the Government of Egypt. Significant changes in the crude oil industry, including fluctuations in the commodity prices and economic conditions, environmental regulations, government policy, royalty rates and other geopolitical factors, could adversely affect the Company's ability to realize the full value of its accounts receivable from the Government of Egypt. Historically, the Company has had a significant account receivables outstanding from the Government of Egypt. While the Government of Egypt has made regular payments on these amounts owing, the timing of these payments has historically been longer than normal industry standard. The receivable balance due from the Egyptian Government was reduced to a manageable level in 2015 as a result of the Company's direct marketing initiative and continued payments from the Egyptian Government. However, there remains a balance due from the Egyptian Government, and there can be no assurance that future payments will occur on a more timely basis or occur at all. In the event the Government of Egypt fails to meet its obligation, such failures could materially adversely affect the Company's financial and operational results.

Foreign Jurisdiction Risk

The majority of the Company's current production is located in Egypt. As such, and in addition to the specific political risks mentioned above, the Company is subject to political, economic, and other uncertainties, including, but not limited to, expropriation of property without fair compensation, changes in energy policies or the personnel administering them, a change in oil or natural gas pricing policy, the actions of national labour unions, nationalization, currency fluctuations and devaluations, renegotiation or nullification of existing concessions and contracts, exchange controls and royalty and tax increases and retroactive tax claims, investment restrictions, import and export regulations and other risks arising out of foreign governmental sovereignty over the areas in which the Company's operations are conducted, as well as risks of loss due to civil strife, acts of war, terrorist activities and insurrections, economic sanctions, the imposition of specific drilling obligations and the development and abandonment of fields.

The Egyptian government could adopt new policies that might result in substantially hostile attitudes towards foreign investments such as the Company's. In an extreme case, government actions could result in forced renegotiation of the Company's existing contracts, termination of contract rights and expropriation of its assets (including crude oil inventory) or resource nationalization. Loss of property (damage to, or destruction of, the Company's wells, production facilities or other operating assets) and/or interruption of its business plans (including lack of availability of drilling rigs, oilfield equipment or services if third party providers decide to exit the region or inability of the Company's service equipment providers to deliver necessary items for the Company to continue operations) as a direct or indirect result of political protests, demonstrations or civil unrest in Egypt could have a material adverse impact on the Company's results of operations and financial condition. In addition, the Company cannot provide assurance that future political developments in Egypt, including changes in government, changes in laws or regulations, export restrictions or further civil unrest or other disturbances, would not have an adverse impact on ongoing operations, the Company's ability to comply with its current contractual obligations, the Company's ability to lift and sell its crude oil inventory to third parties, or on the terms or enforceability of its production sharing and concession agreements or other contracts with governmental entities.

The Company's operations may also be adversely affected by laws and policies of Canada and Egypt affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with the Company's operations in Egypt, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdictions of the courts of Canada or enforcing Canadian judgments in such other jurisdictions. The Company may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, the Company's exploration, development and production activities in Egypt could be substantially affected by factors beyond the Company's control, any of which could have a material adverse effect on the Company.

If the Company's operations are disrupted and/or the economic integrity of its projects are threatened for unexpected reasons, its business may be harmed. These unexpected events may be due to technical difficulties, operational difficulties which impact the production, transport or sale of the Company's products, security risks related to terrorist activities and insurrections, difficult geographic and weather conditions, unforeseen business reasons or otherwise. Prolonged problems may threaten the commercial viability of its operations.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time could be reduced or suspended entirely.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditures or property acquisitions using funds from operations.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the ability of the Company to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired.

Relinquishment Obligations

The Company is subject to relinquishment obligations under its title documents which oblige the Company to relinquish certain proportions of its concession lease and licence areas and thereby reduce the Company's acreage. Additionally, the Company may be unable to drill all of its prospects or satisfy its minimum work commitments prior to relinquishment and may be unable to meet its obligations under the title documents. Failure to meet such obligations could result in concessions, leases and licences being suspended, revoked or terminated which could have a material adverse effect on the Company's business.

The expiry date for the South Alamein concession was January 2019. The Company has resubmitted a request for military access and based on the most recent discussions with EGPC, the Company expects to receive an extension. If the extension is not received, then the South Alamein concession will terminate thereby reducing the Company's acreage, exploration prospects in Egypt and 2019 exploration program by $1.3 million.

Substantial Funding Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the

Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. The Company's ability to externally finance its capital requirements is dependent on, among other factors:

- the overall state of the capital markets;
- the Company's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities in particular.

Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Hedging Risks

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of C$ to US$ or other currencies in order to offset the risk of revenue losses if the C$ increases in value compared to other currencies. However, if the C$ declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the reserves from the Company's assets, and the production from them, will decline over time as the Company produces from such reserves. The Company's participation in the West Gharib, West Bakr, North West Gharib, South Ghazalat, and South Alamein production sharing contracts in Egypt represent major undertakings. The exploration programs in Egypt are high-risk ventures with uncertain prospects for ongoing success. A future increase in the reserves attributable to the Company's assets will depend on both the ability of the Company to explore and develop the Company's assets and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to the Company and may delay exploration and development activities.

Forward-looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Information Technology Systems and Cybersecurity

The Company has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, manage financial resources, analyses seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party partners.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card

details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as on its reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Global Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Company.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Company's ability to market its products internationally, increase costs for goods and services required for the Company's operations, reduce access to skilled labour and negatively impact the Company's business, operations, financial conditions and the market value of its Common Shares.

Egypt Political Risks

Beyond the risks inherent in the petroleum industry, the Company is subject to additional political risks resulting from doing business in Egypt. Since 2011, there has been significant civil unrest and widespread protests and demonstrations throughout the Middle East, including Egypt. Abdel Fattah el-Sisi was elected in 2014 President in Egypt following several years of widespread protests, demonstrations and civil unrest. Since this time, political and economic stability has returned to the country leading to a positive impact in business confidence. As a result of this political and economic stability, on 11 November 2016, the International Monetary Fund ("IMF") approved a three-year, US$12 billion extended arrangement under the Extended Fund Facility with Egypt to support the Egyptian authorities' proposed economic reform.

To date, Egypt has received approximately US$10 billion in funds from the IMF. The IMF noted that the Egyptian government continued to meet nearly all of its commitments under the program, and that the Egyptian economy was showing encouraging signs of recovery following initial stabilization. Although inflation remains high in Egypt, certain economic reform policies have led to Egypt's CPI inflation falling to approximately 20.9% at the end of 2018. However, the IMF has cautioned Egypt not to jeopardize the fight against inflation by easing any economic reforms prematurely. Inflation in Egypt remains highly volatile leading to significant economic impacts over which the Company does not have control, including but not limited to, living costs, operational costs, transportation costs, employment levels, borrowing/lending rates and currency valuation. The Company cannot predict the impact of inflation on oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Input Costs for Materials and Services

Historically, the Company's capital and operating costs have risen during periods of increasing commodity prices. These cost increases result from a variety of factors beyond the Company's control. Increased levels of drilling activity in the petroleum industry in recent periods has led to increased costs of certain drilling equipment, materials and supplies. Such costs may rise faster than increases in the Company's revenue, thereby negatively affecting its profitability, cash flow and ability to complete development activities as scheduled and on budget.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical

conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key personnel insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry can be intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, U.S. securities laws and under the AIM Rules for Companies, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company’s results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market’s confidence in the Company’s financial statements and harm the trading price of the Common Shares.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Litigation

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's financial condition.

Decommissioning Costs

In Canada, liabilities in respect of the decommissioning of its wells, fields and related infrastructure are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Company to make provisions for and/or underwrite the liabilities relating to such decommissioning. It is difficult to accurately forecast the costs that the Company would incur in satisfying any decommissioning obligations. When such decommissioning liabilities crystallize, the Company would be liable either on its own or jointly and severally liable for them with any other former or current partners in the field. In the event that it is jointly and severally liable with other partners and such partners default on their obligations, the Company would remain liable and its decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that the Company incurs may adversely affect its financial condition.

In Egypt, under model concession agreements and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. While the current risk to the Company of becoming liable for decommissioning liabilities in Egypt is low, future changes to legislation could result in decommissioning liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect the Company's financial condition.

In relation to petroleum wells, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that the Company could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

Risk to title due to assignment restrictions

The Company acquired its interest in the South Alamein Concession by acquiring the shares of the contractors under the concession in 2012. It did so with EGPC's knowledge but did not obtain formal EGPC approval for the transfer of any such shares.

Recent models of the Egyptian concession agreement in Egypt (including the South Alamein concession) include restrictive wording that require the government's consent for any direct or "indirect" assignment of rights under the concession, which could be interpreted to include acquiring the voting or equity shares of the contractor party to an Egyptian concession. The government's position on the matter is neither clear nor unified, raising ambiguity and the risk that an executed assignment offshore could be revisited by the government and EGPC. If so revisited, this could result in the contractor being required to obtain the government's consent to deeds of assignment, liability for assignment bonuses and/or the government seeking termination for breach of the concession agreement. There are no reported cases of a concession being terminated on such grounds. The Company considers the continued communication, correspondences and dealings subsequent to the completion of the Company's acquisition as limiting the probability that such risks will materialize. To date, EGPC has recognized and dealt with the Company as though no such approval was required or, if required, was deemed to have been given by EGPC at the time of the transaction.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in US$. The Company's exposure to currency exchange rate risks is primarily limited to Canadian general and administrative expenses which are paid for in C$, United Kingdom (UK) pound sterling and Egyptian pound cash balances. A low value of the Canadian dollar relative to the United States dollar, UK pound sterling and Egyptian pound may positively affect the price the Company receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results. The Company prepares its financial statements in US$ and, as a result, the Company's statement of comprehensive income, statement of cash flows and statement of financial position are impacted by changes in exchange rates between C$, UK pounds, Egyptian pounds and US$.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

AIM

AIM is a market designed primarily for emerging or smaller growing companies which carry a higher than normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List of the UK Listing Authority (the "Official List") or some other stock exchanges. The Common Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List and the share price may be subject to greater fluctuations than might otherwise be the case. An investment in shares traded on AIM carries a higher risk than those listed on the Official List.

Reputational Risk

Any environmental damage, loss of life, injury or damage to property caused by the Company's operations could damage the Company's reputation in the areas in which the Company operates. Negative sentiment towards the Company could result in a lack of willingness of municipal authorities to grant the necessary licenses or permits for the Company to operate its business and in residents in the areas where the Company is doing business opposing further operations in the area by the Company. If the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Company's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Company has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Company's operations caused by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Company's reputation. See *"Risk Factors – Climate Change"*.

Debt Facility Arrangements

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Company's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the Company's borrowing base, reducing the funds available to the Company under the credit facility. This could result in the requirement to repay a portion, or all, of the Company's indebtedness.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable

terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under credit facilities, the lenders under the credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs"*.

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Trading Currencies

The Common Shares trading on the AIM are denominated in British Pounds whereas the Common Shares trading on the TSX are in Canadian dollars and on the Nasdaq in United States dollars. Fluctuations in the exchange rate between the currencies, including the pound sterling, will affect the value of the Common Shares and any dividends the Company may declare in the future, denominated in the local currency of investors outside of Canada.

Liquidity and Arbitrage between TSX, AIM and Nasdaq

There can be no guarantee that the Common Shares will trade at the same price on the TSX, AIM and Nasdaq. Due to different investor sentiments, liquidity levels, transaction costs, taxation rates, regulations or foreign exchange rates. Additionally, TSX, AIM and Nasdaq operate in different time zones and, for instance, news flow from external sources such as regulatory regime changes which affect the Company may be acted upon earlier by an investor on one market ahead of the other.

During the AIM admission process, the Board engaged brokers in both Canada and the UK to manage the migration of shares between the registers kept in Canada and the UK, but there can be no guarantee that this arrangement will eliminate all arbitrage opportunities between the shares traded on the TSX and AIM or that such procedures will be effective.

Dilution and Pre-Emption Rights

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive. In order to finance future operations or acquisition opportunities, the Company may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Company cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Company's securities will have on the market price of the Common Shares.

The Company is not required under Canadian law to offer new Common Shares to existing Shareholders on a pre-emptive basis as is required of companies incorporated under the UK Companies Act 2006. As such, it may not be possible for existing Shareholders to participate in future share issues, which may dilute an existing Shareholder's interest in the Company. However, there are various protections afforded to Shareholders as a result of Canadian securities laws. Additionally, the Company and the Board have undertaken to Canaccord Genuity Limited, its UK Nominated Advisor, that for as long as the Common Shares remain quoted on AIM, the Company will obtain approval by special resolution for issuance of Common Shares in certain circumstances. Shareholders not participating in future offerings may be diluted. The Company may in the future issue options and/or warrants to subscribe for new Common Shares, including (without limitation) to certain advisers, employees, directors, senior management and consultants. The exercise of such warrants and/or options would result in dilution of the shareholdings of other investors.

No Takeover Code Protection

The Company is not subject to the provisions of the UK City Code on Takeovers and Mergers and it is emphasized that, although the Common Shares are trading on AIM, the Company will not be subject to takeover regulation in the UK. However, Canadian laws applicable to the Company provide for early warning disclosure requirements and for takeover bid rules for bids made to security holders in various jurisdictions in Canada.

Actions or Enforcement Judgements

The Company is continued under the laws of the Province of Alberta, Canada, and as at March 13, 2019 the majority of the Company's directors and officers are residents of Canada. Consequently, it may be difficult for investors from outside of Canada, to effect service of process upon the Company or upon those directors or officers, or to realize judgments of non-Canadian courts. Furthermore, it may be difficult for non-Canadian investors to enforce judgments of non-Canadian courts based on civil liability provisions of the non-Canadian securities laws in a Canadian court against the Company or any of the Company's executive officers or directors. There is substantial doubt whether an original lawsuit could be brought successfully in Canada against any of such persons or the Company predicated solely upon such non-Canadian civil liabilities.

Cash Transfer Restrictions

The Company currently conducts the majority of its operations through its foreign subsidiaries and foreign branches. Therefore, the Company could be dependent on the cash flows of these subsidiaries to meet its obligations. The ability of its subsidiaries to make payments to the Company may be

constrained by, among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdictions in which it operates; the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated; and contractual restrictions with third parties. For example, certain governments have imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by a country's central bank. These central banks may require prior authorization and may or may not grant such authorization for the Company's foreign subsidiaries to transfer funds to it and there may be a tax imposed with respect to the expatriation of the proceeds from the Company's foreign subsidiaries.

Title to Assets

Although title reviews may be conducted in Canada prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Due in part to the nature of property rights development historically in Canada as well as the common practice of splitting legal and beneficial title, public registries are not determinative of actual rights held by parties. Further, the fragmented nature of oil and gas rights, which may be held by the government or private individuals and companies, and may be split among a great number of different granting documents, means that despite best efforts of parties, latent defects may not be immediately discoverable. As such, the actual interest of the Company in properties may accordingly vary from the Company's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Company's title to the oil and natural gas properties the Company controls in Canada that could impair the Company's activities on them and result in a reduction of the revenue received by the Company.

Income Taxes

As the Company is engaged in the Canadian petroleum industry, its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) (the "Tax Act") *Canadian Tax Act* and applicable provincial income tax legislation relating to characterization of costs incurred in its business which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. The Company files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. For instance, on January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. The new regime was a positive for future investment and provides for a low crown royalty rate (5%) to be applied to horizontal wells until well production has paid out the capital cost of drilling the well.

Regulatory

In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The following are examples of some of these regulatory risks:

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Liability Management

The Province of Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Company's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Company's compliance obligations. In addition, the liability management regime may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The impact and consequences of the Supreme Court of Canada's decision in the Redwater case on the Alberta Energy Regulator's ("AER") rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will no doubt evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs"*.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of applicable laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental legislation related to the Company's assets, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Conflicts of Interest

Certain directors or officers of the Company may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Non-Governmental Organizations and Eco-Terrorism Risks

The oil and natural gas exploration, development and operating activities conducted by the Company may, at times, be subject to public opposition. Such public opposition could expose the Company to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Aboriginal groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Company to incur significant and unanticipated capital and operating expenditures.

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and options to purchase securities, if applicable, is contained in the Company's Information Circular for the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided for in the Company's financial statements and the management's discussion and analysis for the year ended December 31, 2018. These documents, along with other documents affecting the rights of securityholders and other information relating to the Company, may be found on SEDAR at www.sedar.com and in the Company's Annual Report on Form 40-F for the fiscal year ended December 31, 2018, filed on EDGAR at www.sec.gov.

SCHEDULE "A"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

To the Board of Directors of TransGlobe Energy Corporation (the **"Company"**):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			MM U.S. $	MM U.S.$	MM U.S.$	MM U.S.$
GLJ Petroleum Consultants Ltd	December 31, 2018	Canada	—	132.5	—	132.5
		Egypt	—	206.7	—	206.7
		TOTAL	—	339.1	—	339.1

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 22, 2019.

GLJ PETROLEUM CONSULTANTS LTD

Per: *"Originally signed by"*

Leonard L. Herchen, P. Eng.

Vice President

GLJ Petroleum Consultants Ltd

SCHEDULE "B"

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of TransGlobe Energy Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule A of this Annual Information Form.

The Reserves Committee of the Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and
(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

DATED as of this 11th day of March, 2019.

Per:

(Signed) Randy C. Neely
Randy Neely
President, Chief Executive Officer and Director

Per:

(Signed) Bob MacDougall
Bob MacDougall
Director and Chair of the Reserves, Health Safety Environment and Social Responsibility Committee

Per:

(Signed) Lloyd Herrick
Lloyd Herrick
Vice-President, Chief Operating Officer

Per:

(Signed) Robert Jennings
Robert Jennings
Director and Chairman of the Board

SCHEDULE "C"

Charter of Audit Committee

Our Audit Committee Charter outlines the specific roles and duties of the Committee's members.

GENERAL FUNCTIONS, AUTHORITY AND ROLE

The Audit Committee is a committee of the Board of Directors appointed to assist the Board in monitoring (1) the integrity of the financial statements of the Company, (2) compliance by the Company with legal and regulatory requirements related to financial reporting, (3) qualifications, independence and performance of the Company's independent auditors, (4) performance of the Company's accounting, internal controls and financial reporting process and monitoring business risks.

The Audit Committee has the power to conduct or authorize investigations into any matters within its scope of responsibilities, with full access to all books, records, facilities and personnel of the Company, its auditors and its legal advisors. In connection with such investigations or otherwise in the course of fulfilling its responsibilities under this charter, the Audit Committee has the authority to independently retain special legal, accounting, or other consultants to advise it, and may request any officer or employee of the Company, its independent legal counsel or independent auditor to attend a meeting of the Audit Committee or to meet with any members of, or consultants to, the Audit Committee. In its capacity as a committee of the Board of Directors, the Audit Committee has the power to determine the amount of Company funds that are appropriate for payment of (1) compensation to the Company's independent auditor engaged for the purpose of preparing audit reports and performing other audit and non-audit services, (2) independent counsel and other advisers as it determines necessary to carry out its duties and (3) ordinary administrative expenses as it determines necessary to carry out its duties. The Audit Committee also has the power to create specific sub-committees with all of the investigative powers described above.

The Board of Directors and Audit Committee, as representatives of the Company's shareholders, have the ultimate authority and responsibility to retain and evaluate the independent auditor, to nominate annually the independent auditor to be proposed for shareholder approval and to determine appropriate compensation for the independent auditor. In the course of fulfilling its specific responsibilities hereunder, the Audit Committee must maintain free and open communication between the Company's independent auditors, Board of Directors and Company management. The responsibilities of a member of the Audit Committee are in addition to such member's duties as a member of the Board of Directors.

While the Audit Committee has the responsibilities and powers set forth in this charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete, accurate, and in accordance with generally accepted accounting principles. This is the responsibility of management. Nor is it the duty of the Audit Committee to conduct investigations, to resolve disagreements, if any, between management and the independent auditor (other than disagreements regarding financial reporting), or to assure compliance with laws and regulations or the Company's own policies.

MEMBERSHIP

The membership of the Audit Committee will be as follows:

- The Committee will consist of a minimum of three members of the Board of Directors, appointed annually, each of whom is affirmatively confirmed by the Board of Directors as having satisfied the independence standards specified in all applicable rules of the Canadian provincial securities commissions, the U.S. Securities and Exchange Commission (the "SEC") and any securities exchange on which the Company's shares are traded, with such affirmation disclosed in the Company's Management Proxy Circular.

- The Committee will also consist of all members that meet the definition of "Financially Literate" as defined in National Instrument 52-110 Part 1(1.5) and are able to read and understand fundamental financial statements, including the Company's balance sheet, income statement and cash flow statement. The Committee shall have at least one member that qualifies as a financial expert as defined by the SEC.

- The Committee will not have participated in the preparation of the financial statements of the Company or its subsidiaries at any time during the past three years.

- The Board will elect, by a majority vote, one member as chairperson of the Audit Committee.

- A member of the Audit Committee may not, other than in his or her capacity as a member of the Audit Committee, the Board of Directors, or any other Board committee, accept any consulting, advisory, or other compensatory fee from the Company, and may not be an affiliated person of the Company or any subsidiary thereof.

RESPONSIBILITIES

The responsibilities of the Audit Committee shall be as follows:

Frequency of Meetings

- Meet on at least a quarterly basis, either in person or by telephone.
- Meet with the independent auditor on at least a quarterly basis, either in person or by telephone.

Reporting Responsibilities

- Provide to the Board of Directors proper Committee minutes.
- Report Committee actions to the Board of Directors with such recommendations as the Committee may deem appropriate.

Charter Review

- Annually review and reassess the adequacy of this Charter and recommend any proposed changes to the Board of Directors for approval.

Advice of Counsel

- The Committee shall receive and review any reports from counsel to the Company concerning evidence of any material violation of law by the Company.

Whistleblower Mechanisms

- Adopt and review annually a mechanism through which employees and others can directly and anonymously contact the Audit Committee with concerns about accounting, internal accounting controls and auditing matters. The mechanism must include procedures for receiving, responding to, and keeping of records of, any such expressions of concern.

Independent Auditor

- Recommend to the Board the annual nomination of the independent auditor to be proposed for shareholder approval.
- Approve the compensation of the independent auditor and evaluate the performance of the independent auditor.
- Establish policies and procedures for the engagement of the independent auditor to provide non-audit services. The Audit Committee's pre-approval procedure is to approve all non-audit services to be performed by the Company's auditors in advance of the engagement of the Company's auditors to perform such services. The pre-approval process involves management presenting the Audit Committee with a description of any proposed non-audit services. The Audit Committee considers the appropriateness of such services and whether the provision of those services would impact the auditor's independence, including the magnitude of the potential fees. Once the committee has satisfied itself of its concerns, if any, it then votes either in favor of or against contracting the Company's auditors to perform the proposed non-audit services.
- Ensure that the independent auditor is not engaged for any activities not allowed by any of the Canadian provincial securities commissions, the SEC or any securities exchange on which the Company's shares are traded.
- Ensure that the independent auditor is not engaged for any of the following nine types of non-audit services contemporaneous with the audit:
    - Bookkeeping or other services related to accounting records or financial statements of the Company;
    - Financial information systems design and implementation;
    - Appraisal or valuation services, fairness opinions, or contributions-in-kind reports;
    - Actuarial services;
    - Internal audit outsourcing services;
    - Any management or human resources function;
    - Broker, dealer, investment advisor, or investment banking services;
    - Legal services; and
    - Expert services related to the auditing service.
- Ensure that the independent auditor is compliant with the SEC, any security exchange on which the Company's shares are traded and the Institute of Chartered Accountants of Alberta (Rules of Professional Conduct) regarding Audit Partner Rotation requirements.

Hiring Practices

- Ensure that no senior officer or employee who is, or in the past full year has been, affiliated with or employed by a present or former auditor of the Company or an affiliate, is hired by the Company until at least one full year after the end of either the affiliation or the auditing relationship.

Independence Test

- Take reasonable steps to confirm the independence of the independent auditor, which shall include:
    - ensuring receipt from the independent auditor of a formal written statement delineating all relationships between the independent auditor and the Company, consistent with the Independence Standards Board Standard No. 1 and related Canadian regulatory body standards;
    - considering and discussing with the independent auditor any relationships or services, including non-audit services, that may impact the objectivity and independence of the independent auditor; and
    - as necessary, taking, or recommending that the Board of Directors take, appropriate action to oversee the independence of the independent auditor.

Audit Committee Meetings

- Only members of the Audit Committee have the right to attend the Audit Committee meetings. However, the finance director, internal auditors and external auditors will be invited to meetings of the Audit Committee on a regular basis and other non-members may be invited to attend all or part of any meeting as and when appropriate. The Audit Committee may request the presence of the independent auditor at any Audit Committee meeting.

- At the request of the independent auditor, convene a meeting of the Audit Committee to consider matters the auditor believes should be brought to the attention of the directors or shareholders.

- Keep minutes of its meetings and report to the Board for approval of any actions taken or recommendations made.

Restrictions

- Ensure no restrictions are placed by management on the scope of the auditors' review and examination of the Company's accounts.

- Ensure that no Officer or Director attempts to fraudulently influence, coerce, manipulate or mislead any accountant engaged in auditing of the Company's financial statements.

Audit and Review Process and Results

Scope

- Consider, in consultation with the independent auditor, the audit scope and plan of the independent auditor.

Review Process and Results

- Consider and review with the independent auditor the matters required to be discussed by Statement on Auditing Standards No. 61, as the same may be modified or supplemented from time to time.

- Review and discuss with management and the independent auditor at the completion of the annual examination:
    - the Company's audited financial statements and related notes;
    - the Company's MD&A and news releases related to financial results;
    - the independent auditor's audit of the financial statements and its report thereon;
    - any significant changes required in the independent auditor's audit plan;
    - any non-GAAP related financial information;
    - any serious difficulties or disputes with management encountered during the course of the audit; and
    - other matters related to the conduct of the audit, which are to be communicated to the Audit Committee under generally accepted auditing standards.

- Review and discuss with management and the independent auditor annual and interim financial statements (including related notes and MD&A) at the completion of any review engagement or other examination and prior to public disclosure, and resolve to recommend approval of said documents to the Board of Directors.

- Review and discuss with management and the independent auditor the adequacy of the Company's internal control over financial reporting that management and the Board of Directors have established and the effectiveness of those systems, including, but not limited to, review and discussion of (1) management's report on its assessment of the effectiveness of internal control over financial reporting as of the end of each fiscal year and the independent auditor's report on management's assessment and the effectiveness of internal control over financial reporting, (2) inquiry of management and the independent auditor about significant financial risks, exposures, deficiencies or material weaknesses identified and the steps management has taken to minimize such risks, exposures, deficiencies and material weaknesses to the

Company and (3) any changes in internal control over financial reporting that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting and are required to be disclosed, as well as any other changes in internal control over financial reporting that were considered for disclosure in the Company's periodic filings with the SEC.

- Meet separately with the independent auditor, management and the CFO as necessary or appropriate to discuss any matters that the Audit Committee or any of these groups believe should be discussed privately with the Audit Committee.

- Review and discuss with management and the independent auditor the accounting policies which may be viewed as critical, including all alternative treatments for financial information within generally accepted accounting principles that have been discussed with management, and review and discuss any significant changes in the accounting policies of the Company and industry accounting and regulatory financial reporting proposals that may have a significant impact on the Company's financial reports.

- Review with management and the independent auditor the effect of regulatory and accounting initiatives as well as off-balance sheet structures, if any, on the Company's financial statements.

- Review with management and the independent auditor any correspondence with regulators or governmental agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies.

- Review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's financial compliance policies and any material reports or inquiries received from regulators or governmental agencies related to financial matters.

Securities Regulatory Filings

- Review, prior to filing with regulatory bodies, annual and periodic filings with the Canadian provincial securities commissions and the SEC and other published documents containing the Company's financial statements.

Risk Assessment

- Meet semi-annually with the Officers' Risk Committee to discuss the Company's risk assessment and risk management. One meeting will be an in-depth review of the corporate risk assessment and emerging risks.

- Review the Company's policies with respect to risk assessment and risk management including, without limitation, environmental risk, insurance coverage and the risk of fraud. The Committee also shall discuss the Company's major risk exposures and the steps management has taken to monitor and control them.

Amendments to Audit Committee Charter

- Annually review this Charter and propose amendments to be ratified by a simple majority of the Board of Directors.